Service Date: March 7, 1986

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER Of The Commission's Investigation Of Electric Avoided Cost Rates.	)))	UTILITY DIVISION DOCKET NO. 84.10.64 ORDER NO. 5091c

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APPEARANCES

FOR MONTANA DAKOTA UTILITIES COMPANY:

John L. Alke, P.O. Box 1166, Helena, Montana 59601

FOR THE MONTANA POWER COMPANY:

Daniel O. Flanagan, 40 East Broadway, Butte, Montana 59701

FOR PACIFIC POWER AND LIGHT COMPANY:

Thomas H. Nelson, 900 S.W. Fifth Avenue, Portland, Oregon 97204 and John B. Dudis, Jr., P.O. Box 759, Kalispell, Montana 59901

FOR THE MONTANA CONSUMER COUNSEL:

James C. Paine, Esq., and John Allen, Esq., 34 West Sixth Avenue, Helena, Montana 59620

FOR CHAMPION INTERNATIONAL AND CONOCO, INC:

C. W. Leaphart, Jr., 1 Last Chance Gulch, Helena, Montana 59601

FOR INTERVENORS: GREENFIELD IRRIGATION DISTRICT, MONTANA RENEWABLE RESOURCES, INC., MITEX INC., AND MONTANA SMALL HYDRO ASSOCIATION:

Lisa Leckie, P.O. Box 162, Helena, Montana 59624

FOR INTERVENORS: SUPERIOR ENERGY INC., MONTANA WATER DEVELOPMENT ASSOCIATION, DAN BRUTGER, TOM VENABLE AND ROBERT POLICH:

Ted J. Doney, P.O. Box 1185, Helena, Montana 59604-1185

FOR THE MONTANA PUBLIC SERVICE COMMISSION:

Timothy R. Baker and Eileen Shore, Staff Attorneys, 2701 Prospect Ave., Helena, Montana 59620

BEFORE:

CLYDE JARVIS, Chairman
HOWARD ELLIS, Vice Chairman
JOHN DRISCOLL, Commissioner
TOM MONAHAN, Commissioner
DANNY OBERG, Commissioner

FINDINGS OF FACT

I. Introduction

A. Historic/Procedural Background

1. In 1978, the Public Utility Regulatory Policies Act (PURPA) was signed into law. Section 210 of PURPA directed the Federal Energy Regulatory Commission (FERC) to prescribe rules that encourage cogeneration and small power production facilities (hereafter, collectively referred to as qualifying facilities or QFs). [Now codified at 16 USC §824a-3 (1982).]

2. Section 210 set forth certain constraints that must be followed when developing avoided cost prices including:

> (1) Prices must be just and reasonable and in the public interest;
>
> (2) Prices shall not be discriminatory to QFs; and,
>
> (3) No price shall exceed the incremental cost to the utility of alternative electric power.
>
> 16 USC §824a-3 (b) (1982)

3. The Act defines incremental cost to mean, with respect to electric power purchased from QFs, the cost to the electric utility of the electric energy which, but for the purchase from such QFs, such utility would generate or purchase from another source. 16 USC §824a-3 (d) (1982).

4. In 1980, FERC prescribed rules and regulations implementing PURPA Section 210 [(see 18 CFR §§292.301 et seq. (1985).]

5. In June of 1981, this Commission adopted electric avoided cost rules that incorporated these rules by reference. (See ARM 38.5.1901 et seq.)

6. Also in 1981, legislation was enacted creating what has been referred to as Montana's "mini-PURPA, dealing with avoided cost prices for small power production facilities (amended in 1983 to include cogeneration facilities). Sections 69-3601 et seq., MCA (1985).

7. In 1982, this Commission issued an order in Docket No. 81.2.15 (the Commission's first avoided cost docket) adopting the base-peak method for computing long-term avoided cost prices, and the peaker method for short-term prices. See Order No. 4865.

8. In 1983, this Commission issued an order in its second avoided cost docket, reaffirming the merits of using the basepeak method for computing long-term avoided cost prices. See Order No. 5017, Docket No. 83.1.2.

9. Two significant changes, however, were made in Docket No. 83.1.2: (1) a real carrying charge was adopted for annualizing capital costs; and (2) real and nominal levelized price options were tariffed. The result of these changes was that the value of QF power was tied to QF contract length: the longer the contract, the higher the avoided cost prices (in Docket No. 81.2.15 capital costs were levelized with nominal carrying charges and escalated each year at a nominal inflation rate; contract length, in excess of four years, had no bearing on the avoided cost price).

10. The present avoided cost docket was instituted with the primary objective of revisiting the "appropriate avoided cost methodology" (see Procedural Order, Finding No. 3). That is, precise avoided cost calculations were not the objective of the testimony and hearing in this docket.

11. On December 10, 1984, this Commission issued Order No. 5091a, distinguishing between fully negotiated QF contracts and those that were still being negotiated. Qualifying facilities

with contracts that were fully negotiated would receive the avoided cost prices then in effect; these prices would not be subject to revision as a result of decisions in the present docket. Qualifying facilities without "fully-negotiated" contracts faced the prospect of changed avoided cost prices, depending on the Commission's final decision in the present docket. The Procedural Order of January 17, 1985, set forth issues that all parties were requested to address.

12. In February of 1985, the Commission issued an order in Docket No. 84.10.64 that consolidated Docket Nos. 84.10.64 and 84.11.71 (the MPC general rate case). In March, an order was issued in the same docket establishing procedural safeguards regarding testimony offered in Docket No. 84.11.71.

13. On September 12, 1985, the Commission issued Proposed Order No. 5091b. This order allowed the utilities an opportunity to file tariffs and related cost data. In turn, parties were allowed an opportunity to comment on the Proposed Order, as well as the utilities' tariff and cost filings (see Order No. 5091b, Order Paragraph No. 2). The date set for filing was extended, and all parties were allowed until November 26, 1985, to file comments.

B. Purpose of Docket No. 84.10.64

14. As noted above, the present docket was initiated with the principal intent of revisiting the method(s) that should be used to compute avoided cost prices. The apparent need to revisit this issue arose from circumstances surrounding the Montana Power Company's load/resource balance that was revealed in the first Colstrip 3 docket (Docket No. 83.9.67). Rather than initiate a separate docket for each of the three utilities, it was the Commission's finding that one docket would most efficiently address the issue.

15. In previous avoided cost dockets the Commission adopted what is referred to as the "base-peak" approach to compute avoided cost prices. Previous reasons for using this approach were based on the resources included in each utility's resource plans, combined with the ease of implementation and simplicity. It appears, however, that this approach has not stood the test of time. What the base-peak approach appears to lack, as used by this Commission, is the ability and flexibility to adapt to changing load/resource balances.

16. As evident from the testimony in the present docket, there appears to be numerous conflicting objectives. From a public policy standpoint, the Commission finds that the ultimate objective must be to minimize the cost of generating electricity to the utility through the promotion of an efficient combination of cogeneration, small power production and conventional utility resources. While this ultimate objective appears to be shared by the various parties in the docket, their respective methods by which this objective should be achieved differ significantly.

C. Organization of Order

17. The organization of this order is as follows. First, in Part II the Commission will respond to the various parties' comments. Because of the number and diversity of comments, the Commission has chosen to organize comments and responses first on a party basis and then by issue. The order then is MDU, MPC, PP&L, small-hydro power interests (Mitex et al.), Superior Energy and "other."

18. Following these comments and Commission responses is a revised "proposed" order. The Commission has attempted to make all necessary changes reflective of findings of fact in the comment/response section of this order.

D. Summary

19. The Commission finds no reason to deviate from its initial decision to allow two different options for avoided cost pricing. These two options include: (1) a negotiated option and (2) a default tariff option. The Commission, however, finds merit in expanding upon the price options within the default tariff option. The Commission finds these two options absolutely necessary to achieve efficient short-run and long-run electricity production.

20. The Commission finds need to emphasize the availability of the negotiated option for QFs: If QFs can permit a utility to cancel, defer, or scale down a planned generation resource (e.g., MDU's AVS-III or Coyote, MPC's Ryan or any future coal plant included in MPC's or PP&L's resource plans), then the associated costs of said resource should be the avoided cost price basis, to the extent that such costs are avoided. In fact, if a QF (or QFs) contracts to time the on-line date of

their resources to coincide with the on-line date of the utility's planned resource, <u>no cost discounting would be absolutely necessary</u> in the price calculation. If, however, avoided cost payments are to be made presently as compensation for future costs, discounting is appropriate.

21. The negotiated option may impose significant financial constraints on some QFs. Some QFs have resources that, to be profitable, must be developed soon. But a utility may not plan to add another resource (e.g., hydro, thermal or purchase) for 10 years. As a policy matter, and to minimize costs to the utility (and ultimately electric consumers), the Commission finds that additional resources (either utility or QF) should not be built until needed. This is consistent with the Northwest Power Planning Council's finding for the region:

> Today, the region has a 2,300-megawatt surplus of electricity which could last anywhere from five to more than 20 years. For the moment, there is little need to develop resources than can be developed later.
>
> * * *
>
> This analysis shows that, for extremely short-lived resources of ten years or less, the region gains little benefit from their early development because the region is surplus during most of their life. For resources that are longer lived, the benefits the region would enjoy increase up to a maximum of approximately 3.5 cents per kilowatt-hour.
>
> (<u>See</u> Volume I, 1985 Draft Northwest Conservation and Electric Power Plan, pp. 21 and 8-18.)

22. The Commission finds, however, that it should not raise avoided cost prices simply to make profitable those QF projects otherwise unprofitable. Ultimately electric consumers have to pick up the tab through rates. <u>See</u> PURPA Section 210(b) [codified at 16 USC §824a-3(b) (1982).]

23. QFs that cannot wait until the time a utility needs additional resources to develop their projects have the option of contracting for prices in the default tariff option. While not certain about how the final avoided cost prices will look, a combination of short-run escalating energy prices combined with up to 35 years of fully levelized capacity prices greatly exceeds the 2.0¢ figure recently cited in editorials on this subject. For example, MDU's current escalating energy price is between 1.7 and 1.9¢/kwh; MDU's current capacity price <u>before any levelization</u> is $75.00/kw/yr. But $75.00/kw is effectively 1.71¢/kwh (assuming a 50 percent capacity factor). Then, for MDU a

rough minimum avoided cost price is in the range of 3.4¢/kwh to 3.6¢/kwh. If a QF signs a 35 year levelized contract with MDU, the $75.00/kw figure will be even higher yet; moreover, the energy payment will generally rise over time. With 6 percent average annual escalation, the energy price alone would be around 15¢/kwh in 35 years.

24. Another comparison of the often editorialized 2.0¢/kwh rate is to MPC's avoided cost prices. Based on MPC calculations for a fully levelized 35 year capacity price (which will be changed as a result of this order) QFs would be paid $96.30/kw or roughly 2.2¢/kwh. In turn, on an effective ¢/kwh basis the combined energy and capacity payments equal about 3.70¢/kwh (assuming an average 1.5¢/kwh energy price). In addition, if MPC did not use Colstrip Units 1 and 2 and Corrette, the energy price in 1986 would not go below roughly 1.2¢/kwh: but, this is an unreasonably conservative assumption, since these plants will be run and power purchases made in 1986.

25. For PP&L, and in the case of a QF signing a 30 year levelized contract to begin producing power in 1986, the combined energy (over 2¢/kwh) and capacity (about 1¢/kwh based on a 50 percent capacity factor) price will exceed 3¢/kwh. If the same QF instead began production in 1993 and signed a 25 year levelized contract, the starting value for the combined energy and capacity prices would be in excess of 6¢/kwh; moreover, the energy price in both examples would rise each year. Finally, none of these price comparisons reflect the availability of a real levelized energy price option.

26. This summary would be incomplete without a policy statement on the competitive bid. Around the country (e.g., Maine, Texas) QF power is being acquired via competitive bids. The Commission attempted to obtain a comprehensive analysis of the competitive bid process in this docket, but did not. While not implemented in this docket, the Commission believes that the long-term solution to giving utilities and QFs equal, and consistent treatment is a competitive bid. Implementation of a bid process, however, will require institutional changes. The Commission also believes that a bid process, combined with regulatory oversight, will provide an efficient means of minimizing the cost of producing electricity to both the economy and electric consumers. The minimization of such costs is an objective shared by this Commission and the intent of PURPA.

II. Parties' Comments and Commission Responses

A. MDU

27. MDU submitted three comments on the proposed order. The first is a request to base avoided energy cost prices on either "...a one year forecast of system lambda (sic) or the prior month's actual running costs." MDU states a preference for a one year forecast of system lambda.

28. On reconsideration, the Commission finds merit in tariffing forecast energy prices. However, QFs will have the option of historic or forecast prices.

29. MDU's second comment requests the issue of capacity price levelization be left to negotiation. Additionally, MDU's cover letter points out an alleged contradiction in Finding Nos. 109, 154 and 159.

30. MDU has, in this comment, raised an interesting issue, which is whether prices should be levelized. In turn, the type of levelization is at issue (i.e., real and/or nominal). The Commission finds real levelization to be economically rational. With a real levelized price, the QF would see annual price changes reflective of the changes in general-price inflation; a real levelized price will exceed a current nonlevelized price to the extent the same price is expected to rise faster than the general rate of price inflation.

31. There is also less risk of a QF terminating its contract with a real levelized price: inflation erodes the purchasing power of a nominally-levelized price, but not a real levelized price. Out of this docket each utility must offer both real and nominally levelized capacity prices. Energy prices, while not levelized, in nominal terms, will be levelized in real terms, out of this docket. As a result, a portion of the avoided cost capacity price may be "front-loaded" (levelized) in nominal terms. This will provide a distinction in contracts of varying lengths of the value of capacity, but with increased risk (the issue of levelization is discussed in greater detail later in this order).

32. MDU' s final comment involves the Commission's request in Finding No. 163 for a 35 year forecast of minimum and maximum system lambdas. Because the company currently does not have the capability to forecast system lambda beyond five years, MDU requests acknowledgment by the Commission that the five year forecast satisfies the request for 35 years of forecast data.

33. The Commission finds this last request by MDU to be quite interesting. The fact that MDU does not have forecasts of system lambda beyond five years raises numerous questions. For example, on what basis does MDU plan optimal capacity additions? One would expect future fuel costs to play an important role in such an analysis. How are long-term demand forecasts developed? Price-related demand responses would, in turn, require cost forecasts; but, at least one component of future costs (fuel expenses and related) is not forecast.

34. Aside from the above questions, the Commission finds that MDU must provide its best energy price estimate for out to 35 years. As discussed later, this price data must be provided for illustrative purposes in MDU's tariff, and will be required to compute real-levelized energy prices. The Commission looks forward to an opportunity to better understand how MDU models load/resource balances.

35. Finally, from a reading of MDU's Rates 92 and 93, there appears a need for two language changes. First, both tariffs read, in part, "Monthly capacity payments will be made on the basis of actual avoidance of capacity..." (emphasis added). Based on this language, a QF faces uncertainty as to whether it will ever receive capacity payments from MDU. The Commission finds that QFs shall be paid the tariffed capacity payment for each and every kilowatt produced during the months cited. Note that, as discussed later, QFs with long-term contracts (depending on contract length) will eventually be paid capacity payments each and every month of the year.

36. The second necessary language change regards the source of the capacity prices. MDU's tariff language relates the payments to the capacity costs of combustion turbines and baseload generation. The tariff must be revised to reflect the precise resource(s) on which the prices are to be based (i.e., AVS III, Coyote, MAPP Schedule B, etc.).

B. MPC

37. MPC submitted numerous comments on the proposed order. The first comment deals with the calculation of system lambda. As with MDU, MPC's preference is to compute system lambda on a prospective basis. However, if historic data are used, MPC states that "...a lambda calculation for the month in which QF production occurs would be the most appropriate

treatment...". In other words, QFs would be paid the actual marginal running cost in the month they produce. MPC also notes the appropriateness of a 1 MW decrement if historic data are used, but favors a 10 MW decrement if projections are the basis of system lambda.

38. On reconsideration (and discussed in greater detail later in this order), the Commission finds merit in MPC's proposal. However, both historic and forecast price options shall be offered to QFs.

39. MPC's second comment deals with cost discounting. MPC's comment is that while the Company "...fully supports the use of discounting future plant costs in calculating avoided cost payments," the actual application depends upon load/resource balance. Since MPC is currently capacity deficient, the Company favors de-escalation of capital costs.

40. This second comment by MPC on cost discounting raises an important issue in this docket: <u>when</u> is it, if ever, appropriate to discount costs? Of the parties filing direct testimony in this docket, Dr. Power is the only witness who testified that cost discounting should never be applied to compute current avoided cost prices; even then, at least one of the parties Dr. Power testified on behalf of appears to at times support cost discounting.

41. The issue MPC raised concerns the appropriateness of cost discounting in the case of a utility which is "<u>currently</u> capacity deficient." In such a case, MPC contends that costs should be de-escalated and not discounted. Unfortunately, to sort out the issues raised by MPC involves a discussion of both the default tariff and the negotiated pricing options, MPC's resource options (i.e., hydro upgrades versus regional purchases from BPA and/or other utilities), and the economic meaning of current and constant dollars.

42. At first blush, MPC appears to have created a "gray" area: within the "gray" area it is appropriate to de-escalate. Beyond the "gray" area discounting is appropriate. The boundaries of this "gray" area are uncertain. The Commission finds clarity in Dr. Wilson's testimony:

Q: ASSUME, FOR EXAMPLE PURPOSES ONLY, THAT (1) THE BASE PEAK APPROACH WERE RETAINED AS THE METHOD USED TO COMPUTE AVOIDED COST RATES, (2) THE COST OF BUILDING A COAL-FIRED GENERATING PLANT ($4,000/KW IN YEAR 2000 DOLLARS) IS KNOWN, (3) NO RESOURCE ADDITIONS ARE NEEDED UNTIL YEAR 2000

> AND (4) A LEVELIZED AVOIDED COST RATE MUST BE COMPUTED. WOULD YOU DISCOUNT THE COST FROM YEAR 2000 BACK TO THE PRESENT BEFORE LEVELIZING?
>
> A: ... More generally, if payments (levelized or otherwise) are to begin presently as compensation for future (e.g., year 2000) costs, then it is proper to discount those future costs to their present value as the basis for compensation. (Data Response No. JW-18i to the Commission Staff.)

43. Dr. Wilson's position is that there are two cost categories: current costs and future costs. If it is future costs one is compensated for, then discounting is appropriate. What seems to be MPC's source of confusion is the Company's uncertain resource stream and the meaning of "current dollars." These two issues are taken in reverse order.

44. In its comments, MPC states in part:

> Since a current capacity deficiency reflects potential for a current avoidance of capacity purchases in the calculation of an avoided cost capacity rate, all resource costs used in deriving the avoided capacity cost should be <u>current dollars</u>. (emphasis added)

MPC, however, goes on to correlate "current dollars" with de-escalated dollars. But, this correlation is not correct. The National Bureau of Standards defines "current dollars" to mean "values expressed in terms of the actual prices each year, <u>including future price inflation</u>" (emphasis added)[1]. MPC's definition/use of "current dollars" is more in line with the National Bureau of Standard's definition of constant dollars: "Constant dollars-values expressed in terms of the purchasing power of the dollar at the time the ... analysis is conducted; <u>constant dollars do not reflect future price inflation</u>" (emphasis added). The above terms are widely used and accepted[2].

45. Turning to the second issue, precisely what resources should be the basis of MPC's capacity-based avoided cost price has been problematic (see TR 400-404, and MPC's 1985 Projection of Electric Loads and Resources especially pages 8, 14 and 16). The problem is, no single source of capacity exists that one can get a grasp on. On one hand, MPC indicates the hydro upgrade costs in its 1985 Projection of Electric Loads and Resources should be used to compute avoided capacity costs (TR 403). Further, not until the time of comments was MPC's proposal contested. In

its comments/workpapers, MPC also recommends using BPA's capacity rates for the tariffed rate option (Comment No. 5); however, in MPC's workpapers, which provide "BPA Rate Information," there are a dozen BPA rate options. No evidence exists on other utilities' capacity prices or, for example, Colstrip 4 purchase costs.

46. In MPC's case, we have listed potential resources on which one could base an avoided-cost capacity price. The proposed order focused on one category of these potentially avoidable resources (hydro investments), based on MPC's proposal in this docket. There is, however, an analogy to the calculation of avoided cost energy prices that may help resolve the issue of which resource should be the basis of MPC's avoided capacity prices. Just as MPC economically dispatches all resources to meet energy loads, MPC should be acquiring capacity resources to meet capacity requirements in a least-cost manner. And, just as system lambda is based on a 1 MW decrement of dispatched (and purchased) resources, and not on an average cost of all generating resources, one should similarly pick off a capacity counter-part. Then, what is needed (and what has not been provided) is a temporal cost breakdown of MPC's capacity purchases/acquisitions.

47. PP&L's proposal in this docket is also relevant in resolving this issue of an avoided-cost based capacity price for MPC. Unlike MPC, and based on information in this docket, PP&L is capacity sufficient until about 1993. After 1993, however, PP&L would propose paying BPA's new resource rates for QF capacity: costs would not be de-escalated. Also, there would be no cost discounting after 1993, unless the capacity price was levelized. The same logic is consistent with Dr. Wilson's position on discounting, and in turn, applicable to MPC. That is, since MPC is "currently capacity deficient," BPA's current capacity prices are a relevant basis for capacity-based avoided cost prices: no cost discounting would be necessary except for the levelized option (assuming the BPA rates reflect the most expensive avoidable capacity costs).

48. In keeping with the economic dispatch analogy, one would base avoided capacity prices on the highest cost avoidable capacity that MPC plans to acquire. For the default tariff option this would require a calculation and comparison of the discounted present value of each hydro investment, Colstrip 4 costs (if MPC plans to purchase), and the current relevant BPA rates. The highest cost avoidable capacity over the various periods of levelization (e.g., 5 years) would be the

basis of levelized prices. It is precisely this type of analysis that the Commission finds each utility must perform and which, in turn, shall be the basis of capacity prices.

49. For the negotiated pricing option, the Commission's initial findings remain. The Commission would encourage QFs to scrutinize MPC's hydro construction expenditures (plus AFUDC) in the Company's workpapers. QFs should also obtain from MPC relevant quality characteristics for the same hydro projects. If a QF (or QFs) can demonstrate similar quality characteristics and deliver replacement capacity at a QF cost less than what MPC's resource will cost, then the QF resource should be acquired. Alternatively, BPA capacity rates could be the basis of capacity prices.

50. In anticipation of inquiries on what the Commission means by "similar" and "QF cost," the Commission expects the various parties' engineers and financiers can be of assistance. If the opposing parties reach a point of impasse, then the Commission's complaint process may be used to, hopefully, resolve the issue(s).

51. In its third comment, MPC argues that it is appropriate to reduce the hydro upgrade costs to account for fuel (energy) savings. MPC contends that if such a reduction is not made, "...the QF is functionally paid the energy value twice."

52. There are two aspects to the Commission's response to this comment. First, if a hydro project were the basis of a capacity payment for the default tariff option, then MPC is correct to make a fuel savings adjustment. Second, with the negotiated option, however, an adjustment may be inappropriate. If, for example a QF (or QFs) chooses MPC's actual forecast cost stream for a hydro project to be the basis of avoided costs, then this may be the only basis of prices paid the QF.

53. Another comment by MPC requests the exclusion of off-system sales from loads when computing system lambda. MPC reasons that the exclusion is appropriate because the sales are opportunistic and the benefits should flow to ratepayers.

54. The Commission finds no reason to change its initial decision in this matter. At any given hour a utility has a system lambda reflective of all loads, regardless of origin, and it is this cost that the utility would actually avoid if a QF generated one Kwh and allowed MPC to back off the Kwh it would otherwise generate.

55. In another comment, MPC argues the appropriateness of using BPA rates in developing avoided energy and capacity prices. MPC suggests two appropriate means of accounting for BPA capacity rates. First, when BPA is relied on for capacity prior to the on-line date of hydro additions, it is appropriate to include BPA capacity costs in the tariffed rate option. Second, MPC contends that it is appropriate to "weigh-in" BPA capacity costs, but at the time the first hydro upgrades come on line.

56. To say MPC's plans for capacity additions and capacity-related avoided cost pricing proposals are extremely perplexing, is an understatement. On the load/resource balance side, MPC states that it is "currently capacity deficient." This suggests MPC must make capacity purchases today. On the supply side, however, MPC plans a hydro addition no sooner than 1989 (Ryan); in Comment No. 5, MPC states that BPA rates are an appropriate basis for the "tariffed rate option," but only "to the extent" MPC relies on BPA for capacity prior to 1989. Then, we have the 12 BPA rate schedules MPC filed.

57. In summary, and based on MPC's proposal, the default tariffed option would reflect BPA's rates if MPC relied on BPA prior to 1989; and, if MPC did not rely on BPA capacity purchases prior to 1989, it is appropriate to "weigh-in" the cost of BPA capacity purchases with hydro costs. This is enough uncertainty to stifle any QF development.

58. The following elaborates on Finding Nos. 45 through 48 above and 245 below which provide a partial response to MPC's comment on using BPA rates in the development of capacity prices. Certain BPA documents indicate that seven years notice must be given to take power on BPA's NR rate schedule[3]. However, the Commission understands that MPC may purchase power at NR rates upon as little as six months notice; apparently this shorter time period is due to BPA's surplus conditions, combined with the fact that MPC and BPA have a Power Sales contract. Moreover, BPA's SP-85 capacity rate of $5.90/kw/month, which is an alternative BPA capacity price, is not too different from the annual average NR-85 capacity price of $5.77/kw/month. Until such time as the Commission has received a better estimate of avoided capacity costs, BPA's current NR-85 capacity rates must be used in computing capacity prices for the default tariff option.

59. In Finding No. 163, the Commission requested each utility to provide a minimum estimate of system lambda for each of the next 35 years. In another comment, MPC contends that energy payments should not be fixed over the life of a QF contract. However, MPC suggests that if the Commission requires a part of the energy payment to be fixed, the fixed portion be based on the running costs of the utility's least expensive operating thermal resources. MPC further states that this component should be fixed in real terms.

60. The Commission finds that one practical floor level below which system lambda could be guaranteed not to fall (at least until the time MPC adds a more efficient thermal plant -- beyond year 2005) is the fuel adjusted cost of MPC's most efficient plant (i.e., Colstrip 3). From MPC's workpapers the "Bus Cost" of Colstrip 3 equals 7.388 mills/Kwh (assumedly in 1985 dollars). This amount adjusted for O&M, working capital, fuel inventory and line losses would be a relevant floor in about year 1985 (but, contrast MPC's response MC No. 1-55 in Docket No. 84.11.71); in turn, this floor would assumedly rise at roughly the rate of inflation. In this regard, see the below discussion on real-levelized energy prices. If MPC were willing and able to sell any QF power off-system, an economically relevant floor would be the minimum off-system sales price (see Finding No. 245 below).

61. In one comment, MPC informs the Commission that the Company will submit a cost tracking mechanism at a later date.

62. MPC should plan to integrate cost recovery with other ongoing dockets to minimize administrative costs.

63. Regarding the Commission's directives concerning information barriers, MPC proposed that the Commission's finding apply to year 1986. Thereafter, MPC requests that the information be provided once per year.

64. See the Commission's response to, PP&L's proposal in this regard (Finding No. 78 below).

65. Finally, MPC proposed a method for administering the default tariffed option; this method would feature paying QFs a price equal to the actual average running cost for the previous month for all production during the same month.

66. With the exception of MPC's reference to "actual average" and "average actual" running costs, the Commission finds MPC's proposal to have practical merit. Also, MPC's language, "for that month," is assumed to imply the previous month; see the Commission's decision in this regard in Finding No. 38 above. With regard to MPC's reference to "average" running costs, which appears in Comment No. 9 and Schedule QFLT-85, the Commission does have a concern. First, the tariff must be revised to refer to marginal running costs. Secondly, line losses of 8.3 percent and an opportunity sales adjustment must be added to the list of three items under Definition No. 3.

67. There is one other concern that the Commission has with MPC's proposed tariffs. In the first avoided cost docket, the Commission tied capacity payments to a ratio of the QF's actual capacity factor and a combustion turbine's 85 percent availability factor. Clearly, energy and capacity are two distinct products. QFs must be paid a capacity price regardless of their energy production. For example, imagine a QF that only produced power at the time MPC would otherwise purchase capacity off-system. The QF could allow MPC to avoid the costs of capacity purchases and yet may have an annual load factor less than 10 or 20 percent. The QF would effectively be penalized in its capacity payments due to a low annual average capacity factor (also see Finding of Fact No. 276 on seasonality). The other two utilities recognized and excluded such an adjustment from their respective tariffs. MPC must do the same.

C. PP&L

68. In its first comment (to Finding No. 133), PP&L notes that it intends to use the same project capacity costs recently filed in Docket No. 85.10.41; this cost data will be in lieu of the data filed in Docket No. 84.10.64.

69. The Commission does not recognize any problem with this proposal (see Finding No. 252 below).

70. In its second comment (to Finding No. 139), PP&L proposed to not include variable O&M, fuel inventory or working capital adjustments to system lambda.

71. The Commission is troubled by PP&L's position that fuel is the only avoidable variable cost. The Commission rejects PP&L's position. PP&L's argument that there are no studies

correlating avoided O&M etc., with only a small change in load ("1 MW to 10 MW") is weak on its face. There are numerous reasons for requiring PP&L to include the adjustments required in the proposed order. First, the Electric Power Research Institute (EPRI) has identified two types of operating costs which include fixed and variable O&M, where "...fixed merely implies that the cost is not a function of the amount of energy generated."[4]

72. Two other sources, provide a breakdown of types of variable costs, as well as magnitudes, but not for each and every generating unit on the PP&L system. For example, in PP&L's power sales agreement between PP&L and Black Hills Power and Light Company[5], PP&L estimated non-Fuel "variable costs" for Colstrip 3 in 1985 to amount to about 7.3 mills/Kwh. One can then question what PP&L means by "variable." (Certain costs are variable if for another utility and fixed if for a QF).

73. In addition, both MPC and MDU acknowledge the existence of variable O&M, Fuel Inventory and Working Capital. Further, the FERC's avoided cost/regulations acknowledge the avoidability of certain O&M costs [See Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12214 (1980)]. Moreover, an economist with the Oregon Public Service Commission commented in this docket that variable O&M expenses exist (see Exh. No. 13, p. 2).

74. Once more, the Commission finds that PP&L must provide and incorporate estimates of O&M, Working Capital and Fuel inventory costs. Such costs must be included in PP&L's energy avoided cost calculations for each affected thermal plant (e.g., Centralia and Jim Bridger). PP&L must provide detailed workpapers illustrating how it computes these three cost components.

75. In another comment (to Finding No. 140), PP&L expressed concern with the Commission's required 8.3 percent line loss adjustment. Apparently, PP&L would prefer a case-by-case (QF-by-QF) analysis of the "complex interplay of many factors."

76. The Commission finds no reason to change its initial decision in this regard (see Finding No. 67, of Order No. 5017). PP&L has not made a substantial showing to this Commission which would justify any modification of this standard. Accordingly, the Commission continues to find reasonable an 8.3 percent line loss figure.

77. In the next comment, PP&L proposed an alternative to the Commission's directives concerning information barriers (Finding No. 157). PP&L proposes that each utility satisfy this requirement via an existing Commission rule, specifically ARM 38.5.1501(3).

78. The Commission finds merit in this proposal. It shall also apply to MDU and MPC.

79. PP&L's next comment (to finding No. 159) has several facets. First, PP&L raises the issue of using "actual" or "allowed" fuel costs in computing system lambda; in this regard, PP&L argues for using "consistent assumptions."

80. This first point by PP&L is rejected. Each utility must use actual and not Commission-allowed coal costs (from retail rate cases) in the calculation of system lambda. This decision is consistent with the Commission's objective of reflecting, as much as possible, costs to the utility and not ratepayers. If the Commission were to be consistent in the manner that PP&L suggests, then one would turn to the results of PP&L' s annual retail rate cases for all avoided cost information. But, it is incremental costs to the utility, and not the ratepayer (e.g., OC-D treatment of incremental plants), that the FERC's and this Commission's rules require as the basis of avoided cost prices.

81. PP&L's second point deals with the Company's proposal to include wholesale power marketing benefits in payments to QFs. This is the opportunity cost component of PP&L's proposed fixed energy prices. As discussed later in this order, the Commission, on reconsideration, approves PP&L's proposal. While approving PP&L' s proposal on economic grounds, the Commission shares the Oregon Commission's concern that the estimates are "too speculative" and customers should not be exposed to the uncertainties associated with the sales (TR 72). The Commission is unaware of any other state commission that has adopted a similar proposal. However, in the case of PP&L, the customer risk may not be substantial, given the approximately 2.5 mill/kwh value before any reductions for transactions costs (TR 72-76).

82. PP&L's third point regards the jurisdictional cost responsibility of incremental work loads. Specifically, PP&L proposed that any increased costs associated with the Montana Commission's adopted avoided cost methodology be allocated to PP&L's Montana customers only.

83. This request by PP&L is denied. However, once PP&L has set forth a definitive list of administrative costs (and otherwise) that resulted from PP&L's compliance with each and every request by other state and federal agencies (e.g., other commissions, natural resource departments etc.), and established how these costs were allocated among the six state jurisdiction, the Commission may consider this request by PP&L. The Commission would also note that at least the Oregon Commission supports inclusion of variable O&M costs in an avoided cost calculation (see Exh. No. 13, p. 2).

84. Finally, with regard to the Commission's decision to base energy prices for one option on historic data, the Commission finds support from the often quoted (e.g., TR 479) regulatory economist Alfred Kahn. In "tempering principle with practicality," Dr. Kahn suggests using historic costs as one practical means of marginal cost pricing.

85. In Finding No. 160, the Commission requested that each utility provide a minimum of 10 years (now 35 years) of forecasts, annual running costs, etc. For illustrative purposes, each utility was to include such information in the tariff filings. PP&L has responded that the requested data was supplied in this docket.

86. In this regard, the Commission has several requests. First, PP&L must clarify in final workpapers the intent of Appendices A through D. The apparent errors on Appendices A and C must also be corrected. Further, on Appendix D, PP&L must clarify which columns are the prices QFs would receive.

87. PP&L also responded to the Commission's request for each utility's best cost estimates for incremental resource additions, by providing the Company's best estimate of what BPA's Power Sales Contract with BPA will be from 1993 to 2019.

88. The Commission would note that whereas Mr. Rust's initial testimony (Appendix F) assumed 5.8 percent annual growth after 2005, PP&L's forecast prices assume a 7.31 percent average annual growth rate.

89. In its final comment to Finding No. 163, PP&L provided minimum and maximum system lambda estimates.

D. Small Hydro Power Interests[6]

90. In its comments, Mitex et al. (hereafter Mitex), addressed ten general areas. Each general area involves numerous sub-issues; the Commission will attempt to respond to all issues raised.

91. It is important to note the assumptions Mitex made to justify its avoided cost pricing proposal: (1) PURPA mandated the encouragement of QFs at any cost[7]; (2) at the margin, the region's resource plans, are more relevant for setting an individual utility's avoided cost prices, than the same utility's own resource plans; (3) the timing of marginal resource needs is irrelevant, we should still indicate to QFs via avoided cost pricing, that we need the same resource today; and (4) no Montana utility will negotiate a price. This Commission, cannot accept these assumptions.

92. In the comments filed by Mitex, it is stated in pertinent part that "... it is surprising to find in this proposed order not a single mention of the explicitly stated intent of PURPA Section 210 to 'encourage' the development of independent electric power resources" (emphasis added).

93. For the benefit of Mitex, the very first finding of fact in the proposed order stated:

> 1. In 1978, the Public Utility Regulatory Policies Act (PURPA) was signed into law. Section 210 of PURPA directed the Federal Energy Regulatory Commission (FERC) to prescribe rules that encourage cogeneration and small power production facilities (hereafter, collectively referred to as qualifying facilities or QFs). Order No. 5091b, Finding No. 1. (emphasis added)

Moreover, in Finding No. 15 of the proposed order, the Commission recognized the public policy objective of PURPA. Although the objectives of PURPA were many, it is fair to say Congress had intended the increased efficiency in the use of facilities and resources by electric utilities.

94. The congressional mandate imposed upon the FERC by PURPA to prescribe rules that "encourage" QF development was not without constraints: PURPA did not envision unharnessed QF development. In PURPA Congress restricted the "encouragement" objective. These constraints are that avoided cost rates[8]:

> (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

> <u>No such rule prescribed. . .shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.</u>
> 16 USC §824a-3 (a) (1982) (emphasis added)

95. The comments filed by Mitex fail to recognize these constraints, particularly the emphasis upon setting avoided cost rates that do not exceed the incremental costs to the electric utility of alternative electric energy.

96. Mitex's second general comment concerns the use of MPC's hydro upgrades. The following findings respond to this and related comments.

97. The most general concern raised by Mitex is that the Commission has used an MPC resource plan that excludes hydro upgrades. In this docket, the Commission relied on MPC's testimony which proposed to base capacity prices on hydro upgrade costs (TR 403). These hydro upgrades are included with MPC's other "tentative" purchase power resources in the Company's March, 1985 Projection of Electric Loads and Resources (PELRs). The Commission considers this March, 1985 plan "current" until updated in year 1986. The Commission, interprets this "current" plan to include hydro upgrades. MPC's Tables 9 through 14 each have a footnote that reads:

> 3. In the event purchased power is not available, hydro upgrades and development may eventually be considered as a partial replacement of purchased power and could include upgrades at Kerr, Thompson Falls, and Ryan, and development at Hebgen.

Mitex interprets this to mean the current plan excludes hydro upgrades. In any case, as noted above, MPC proposed to base capacity prices on hydro upgrade costs.

98. In addition, Mitex states that "The Salem resource was always listed ahead of the hydro upgrades" (comments, p. 10). This statement is inaccurate. At Table 11 of MPC's 1984 PELRs, the "Ryan Upgrade" is scheduled to come on line in 1993, while Salem is scheduled to come on line in 1996.

99. There is another inaccuracy in Mitex's comment in this regard. This one, however, is not due to scrutiny of past MPC PELRs, but rather to MPC's tentative 1986 PELR. On December 2, 1985, MPC presented Preliminary 1986 Load/Resource Projections. This PELR also includes the

"Ryan Upgrade," and no coal plants. In light of the above, the Commission finds inaccurate the following comment by Mitex:

> MPC makes clear in its filing in response to the proposed order that it is not currently planning to invest in the hydro upgrades. (Power Comments, p. 11)

100. Mitex's third general comment concerns the timing of MPC's resource needs and the calculation of avoided costs. The following findings address this issue.

101. First, Mitex alleges that "PP&L has made major capacity purchases in the last year because it is deficient." Regarding this comment, the Commission requests that PP&L provide certain information in its workpapers in response to this order. PP&L must explain why it is making capacity purchases, as Mitex alleges, when it has proposed to this Commission that only discounted capacity prices be offered before 1993. PP&L must show why this Commission should not tariff nonlevelized capacity-based avoided cost prices prior to 1993, as Mitex contends is appropriate.

102. Second, the casual reader is cautioned by the Commission to distinguish between the types of capacity deficiencies. An optimally designed utility system would include mixes of both peaking capacity and baseload capacity. (See, for example, variables "FCB" and "FCP" in Dr. Wilson's "LRMC" equation.) A utility may be deficient in one type of capacity and have a surplus of the other type; also, a utility may be deficient or surplus in both types of capacity. The Commission hereby requests each utility to clarify the types of deficiencies contemplated in their respective resource plans.

103. In another area, Mitex comments that in calculating avoided cost rates, "all those QF resources not now operating or under construction have to be removed from the plan." (pp. 17-18) This comment by Mitex impacts certain aspects of both tariff options (i.e., the default and the negotiated options). In computing forecasts of illustrative running costs, per Finding No. 160 of the Proposed Order, MPC must exclude all QF power that is not "fully negotiated." Capacity prices must also be computed excluding all nonfully-negotiated QF contract capacity. The Commission finds that use of the "fully negotiated" criterion is more practical at this time. But, the point raised by Mitex is well taken. MPC must discuss in its final workpapers, to the extent possible, what constitutes default with each of the contracts making up the 91 MWs of fully negotiated QF capacity. Only upon

default would it seem appropriate to cut back on the assumed 91 MWs of fully negotiated QF capacity for MPC (the Commission understands that no other utility has "fully negotiated" QF contracts). The FERC's rules and regulations would also appear to argue for excluding the QF power (but only QF power over and above MPC's fully negotiated 91 MWs)[9].

104. In its next general comment, Mitex states that a utility's resource plan should not be the basis of that utility's avoided costs. This comment is consistent with the following earlier testimony of Mitex's witness Dr. Power:

> Q. Dr. Power, is it your recommendation to base avoided cost rates on base load coal units hinge upon a determination of base load coal units are cost effective as compared to alternative long-term resources?
>
> A. No, it's based upon the conclusion that base load thermal units are the marginal production units in the region's utilities' production plans. (emphasis added) (TR 498)

According to Mitex, it is the region's long-range plans for coal plants that should be used to compute utility's avoided cost prices. The Commission has three comments in this regard.

105. First, Mitex ignores the language of PURPA, the FERC regulations, and this Commission's definition of avoided costs:

> "Avoided costs" means the incremental costs <u>to an electric utility</u> of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such <u>utility</u> would generate itself or purchase from another source. <u>See</u> 16 USC §824a-3(d) (1982); 18 CFR §292.101(b)(6) (1985); ARM 38.5.1091(a) (emphasis added)

106. That is, the above definition focuses on the costs to a utility and not a region's costs. In addition, a "fallacy of composition" criticism arises with Mitex's proposal. One only has to take load/resource balance limits for an individual utility vis-a-vis the region to see the flaw in such a proposal (e.g., Black Hills Power and Light versus PP&L).

107. There is another relevant criticism which involves the regional load resource balance. In order for Mitex's proposal to be operable, one must have a clearly defined region and a specific load resource balance (forecast) in mind. For example, if the Commission were to select the

Northwest region and the Northwest Power Planning Council's (Draft) low forecast as the relevant load/resource balance, we would not base avoided cost prices on coal-fired generating plants, since there are no coal plants in this forecast. Similarly, there is no coal plant in the NWPPC's (Draft) medium-low forecast. Only in the Council's "high" load scenario is a new thermal plant needed in the region before year 2002 (1985 Draft Plan, p. 8-12). In turn, the resolution of such a proposal also raises the discounting issue.

108. In the proposed order issued in this Docket, the Commission noted that Dr. Power, in previous testimony before the Commission, acknowledged the economic merit of the peaker approach. (See Order No. 5091b, Finding No. 32.) No comments were received from any party which challenged the accuracy of this finding. The comments filed by Mitex now challenge the use of system lambda to calculate avoided energy costs. In summary, Mitex contends that system lambda should not be included in any avoided cost price paid to QFs. Mitex appears to argue that PURPA did not intend system lambda to be an avoided cost price basis.

109. This comment by Mitex is inconsistent with the previous testimony of its witness Dr. Power (see Testimony of Thomas Michael Power, on behalf of the Montana Public Service Commission Advocacy Staff, July, 1981). Moreover, Mitex's proposal to exclude lambda in an avoided cost price conflicts with FERC's rules and regulations implementing PURPA.

110. The FERC's intent was, in part, to base avoided cost prices on system lambda:

> The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses.
>
> * * *
>
> The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the Principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The

> utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12214, 12216 (1980). (emphasis added)

111. There is an inaccurate impression conveyed by Mitex regarding how low MPC's marginal running costs might go. On pages 25, 26 and 27 of its comments, Mitex suggests that MPC's marginal running cost, and in turn, avoided costs will lie in the 7-8 mill/Kwh range. This impression is misleading to the casual reader.

112. At least two adjustments would have to be made to make this 7-8 mill/Kwh floor avoided energy cost price, as conveyed by Mitex, more realistic. First, one should make adjustments for O&M, fuel inventory, working capital and line losses. MPC's compliance workpapers that set forth MPC's September, 1985, fuel costs for Colstrip 3, reveal a 7.39 mill/Kwh figure. Adding 3.7 mills/Kwh (an estimate, but also from MPC's workpapers) to reflect the above noted costs, equals 1.109 mills/Kwh. Finally, a line loss adjustment of 1.083 percent raises this figure to 1.2¢/Kwh: these adjustments alone increase Mitex's floor figure by over 70 percent. But, this is not all one can do to estimate a realistic floor avoided cost energy price. (This is only for the energy price; addition of the capacity price will raise the total avoided cost price signal to QFs.)

113. MPC has more thermal units than just Colstrip 1, 2 and 3. MPC has a 180 MW coal fired unit called the Corrette Plant in Billings, Montana. Unless Mitex is contending that Corrette will never operate, then it should also be factored into Mitex's analysis. In turn, one can estimate Corrette's avoidable cost (adjusted for O&M, line losses etc.). MPC's compliance workpapers indicate that the fuel cost alone is 1.048¢/Kwh. Assuming the same O&M and line loss adjustments, the avoidable running cost of Corrette in September, 1985, was about 1.535¢/Kwh: a figure 120 percent greater than Mitex's 7 mill figure.

114. Additional Commission comment is relevant in this analysis concerning the floor avoided energy price of the default tariff option. First, the FERC's rules did not say system lambda should be used only if it was a high figure: this would be nonsense. Under the FERC's rules, the

level of the actual system lambda is immaterial. Second, neither Colstrip 3 or Corrette will always be the sole basis of a system lambda calculation: the 1 MW decrement calculation will normally have a mix. of resources on which it is based. Third, and perhaps most importantly, the avoided cost price for energy will change over time, and on an annual average basis will generally rise with the rate of inflation. Finally, if MPC's energy prices in the default option are too low, then the Commission would encourage QFs to wheel their power to the other states in the region.

115. A final comment in this general area involves Mitex's statement regarding the use of system lambda:

> Clearly this is an effort at minimizing the incentives to QFs rather than providing the maximum economically rational incentives.

116. The Commission assumes Mitex's proposal in this docket, to pay QFs in excess of 50/kwh, would be in Mitex's words an "economically rational" incentive [also see Finding No. 85 in the proposed order where it is reiterated that Dr. Power's proposal would escalate (increase) avoided costs from the previous docket and, in addition, tack on additional price incentives to reflect historic transmission investments)]. But on the other hand, the maximum price contained in the Northwest Power Planning Council's draft 1985 plan[10] for nonlost-opportunity generating resources (in real levelized 1985 dollars) is about 3.5/ for a 50 year resource. That is, the Council's ceiling "avoided regional cost" is 3.5¢/Kwh (and lower for shorter lived resources). Mitex suggests, via Dr. Power's testimony, that the regional load/resource balance is the relevant basis for avoided cost prices (TP 498). It would seem to follow, then, that the NWPPC would find Mitex's proposal economically irrational.

117. In addition to Mitex's proposed changes to the tariff (see Finding No. 66 in this order), the Commission interprets Mitex's comments to be a criticism of using historic in place of projected marginal running cost data.

118. Several Commission comments are in order. First, the proposed order provided the Commission's rationale for using historic data (see Finding Nos. 137 and 138). Second, whereas Mitex finds historic data to be an improper price basis, others do not (see Alfred Kahn's Volume I The Economics of Regulation, pp. 82, 83, and Finding No. 84, supra). Given the Commission's

decision to also tariff forecast energy prices (one year and longer term real levelized), Mitex's concern may be somewhat mitigated.

119. In its comments, Mitex also addresses the potential supply of QF production. In this regard Mitex alleges that "this Commission's proposed order would put Montana's avoided cost rates near the bottom (sic) of the range of rates available in the region."

120. In response to this charge by Mitex, the Commission would direct the reader to the attached Table 1. The Commission would note that, while possible, it is difficult to make a precise rate comparison due to the differences featured in the various rates. Some rates are "first year" and escalate, and others are levelized for the term of contract. For PP&L, the highest price outside of Montana appears to be in Idaho; however, PP&L has filed in Idaho to substantially lower its avoided cost prices and approval is pending by the Idaho Commission (TR 63, 64). Clearly, one can find avoided cost prices in other states as low or lower than those this Commission will tariff.

121. Also relevant in this comparison is the Northwest Power Planning Council's finding that new electric generating resources have a value to the region of less than 3.5¢/Kwh (1985 dollars and for resource lives of 50 years or less):

> Today, the region has a 2,300-megawatt surplus of electricity which could last anywhere from five to more than 20 years. For the moment, there is little need to develop resources that can be developed later.
>
> * * *
>
> This analysis shows that, for extremely short-lived resources of ten years or less, the region gains little benefit from their early development because the region is surplus during most of their life. For resources that are longer lived, the benefits the region would enjoy increase up to a maximum of approximately 3.5 cents per kilowatt-hour.
>
> (See Volume I, 1985 Draft Northwest Conservation and Electric Power Plan, pp. 21 and 8-18.)

Table 1

Comparison of Escalating Avoided Cost Prices
in Neighboring States

	On-Peak	Off-Peak
Montana (estimated and pending)		
MDU[1]		
Energy ¢/Kwh	1.914	1.727
Capacity $/Kw/Month	12.50	12.50
MPC (estimated annual average)[2]		
Energy ¢/Kwh	1.535	1.535
Capacity $/Kw/Month	7.81	4.31
PP&L[3]		
Energy ¢/Kwh	1.94	
Capacity $/Kw	(See footnote)	

[1] Source: MDU's Energy and capacity prices were derived from Rate 93; this Rate was filed in response to the Commission's proposed order. The capacity price of $12.50 is for 6 months per year.

[2] Source: Energy is MPC's September, 1985, estimate. Capacity is from BPA's NR-85 rate.

[3] Source: PP&L's Schedule 87 filed in response to this Commission's proposed order. Note, if a QF signed an eight year contract (in 1986) it could get 38¢/kw/month. A 30 year (in 1986) contract would pay $3.55/kw/month.

	30 Year	Non-Firm
North Dakota		
MDU[4]		
Energy ¢/Kwh	0.95	2.363-1.862
Capacity	3.08¢/Kwh	$12.50/kw

	On-Peak	Off-Peak
South Dakota		

4 Source: Based on personal Communication with Wally Owen of the State's Public Service Commission on December 19, 1985, and TR 317.

MDU[5]		
Energy ¢/Kwh (winter-summer)	2.314-2.169	1.881-1.669
Capacity $/Kw/Month	12.50	12.50

Black Hills (see footnote #5) Power and Light	
Energy ¢/Kwh	2.05
Capacity $/Kw	0

	< 100kw
Wyoming	
MDU[6]	
Energy ¢/Kwh	1.47
Capacity $/Kw/Month	3.91

	Fixed for 35 Years
Idaho[7]	
PP&L	
Energy ¢/Kwh	6.32
Capacity $/Kw/Month	7.45
Idaho Power Co.	
Energy ¢/Kwh	4.42 ¢/Kwh

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[5] Source: A combination of responses by the state's PSC to a questionnaire from the Montana PSC in May of 1985, and personal communication on December 18, 1985.

[6] Source: Personal communication with the Wyoming Commission on December 17, 1985.

[7] Source: A combination of the Idaho Commission's response to a Montana questionnaire and personal communication on December 18, 1985.

Capacity $/Kw		0
		Fixed For
	1 Year	35 Years
Washington Water Power		
Energy ¢/Kwh	0.8-1.7[8]	3.6-7.38
Capacity $/Kw	0	0
	Non-Firm	Firm
Washington[9]		
PP&L		
Energy ¢/Kwh	1.55	1.7
Capacity $/Kw	0	0
	1 Year	
Puget Sound Power & Light		
Energy ¢/Kwh (winter-summer)	1.7-1.02	
Capacity $/Kw	0	
	Partially Levelized	
	5 Year	35 Year
Washington Water Power		
Energy ¢/Kwh		

[8] The range of rates depends on the season of production. These rates are for a QF beginning operation between July, 1985 and June, 1986.

Source: December 17, 1985 communication with Richard Kindsvatter of the Idaho Public Service Commission.

[9] Source: From a combination of Washington Utilities and Transportation Commission's response to the Montana Commission's questionnaire, and personal communication with James Levesque on December 18, 1985. The Washington Water Power rates were filed in Docket UTF 85-372, and are for years 1985-June, 1987.

Levelized	1.8-0.9	6.0-2.9
Escalating	1.07-0.8	1.7-0.8
Total (Range):	3.5-1.7	7.7-3.7
Capacity $/Kw	0	0

122. In its last general comment Mitex criticizes the notion of discounting future costs to arrive at current avoided cost prices. Based on the initial testimony of its witness Dr. Power, Mitex would assumedly propose to continue basing avoided cost prices for each utility on the escalated costs of historic investments. In addition, and for MPC, Mitex would raise the resulting prices to include transmission costs. The Commission notes that comments filed by Mitex on November 15, 1984, entitled "Regarding Proposed Commission Action" suggest that cost discounting is a normal procedure to arrive at true avoided costs. Now, in its comments on the proposed order, Mitex clearly disfavors cost discounting.

123. In response, it is important to recognize that the Commission's proposed order featured two pricing options: (1) a negotiated option and (2) a default tariff option. These two options were tariffed in an attempt to achieve short- and long-run efficiencies in production. The negotiated option is an attempt to allow QFs the opportunity to supplant resources in each utility's plans, or a long-run efficiency objective. With both this option and advance planning by QFs, there may be no need to discount any costs. The issue is one of QF timing. If QFs schedule their resources to come on line when a utility needs resources, no cost discounting is absolutely necessary. If however, as Dr. Wilson argues (see Finding No. 42 above), QFs come on line in advance of need, then costs should be discounted.

124. The Commission concludes that the evidence as well as the weight of logic in favor of cost discounting, calls for a rejection of the position advocated by Mitex (and Mitex's witness, Dr. Power). As noted in the Proposed Order in this docket, with Power's proposal to not discount, but rather de-escalate future costs, it is immaterial whether ratepayers have a current or future need for a resource. (See Order No. 5091b, Finding No. 145.)

125. Other economists disagree with Mitex's proposal to not cost discount. Dr. Wilson supports cost discounting (see Finding No. 42 above), as does the FERC (with regard to avoided cost pricing)[11].

126. Further, an economist with the Montana agency charged with siting new generation facilities has applauded the proposed order for finally recognizing the importance of cost discounting in the calculation of avoided cost prices[12]. Mitex's proposal would have the Commission retain the previous pricing methods criticized by DNRC's economist.

127. Finally, Dr. Paul Samuelson's introductory economics text reminds students of economics of the one "golden rule" for the correct analysis of all investment decisions: use the discounted present value criterion[13].

128. Mitex also requests that the Commission specify how the discounting should be carried out. If a utility's future cost estimates are in current dollars (i.e., include inflation), then a nominal discount rate should be used. If on the other hand, future costs are in, for example, constant 1986 dollars, then a real discount rate should be used.

E. Superior Energy, Inc.

129. Mr. Ted Doney, on behalf of Superior Energy et al., filed brief comments that incorporated by reference its own briefs, and those briefs filed by the parties that Dr. Power testified on behalf of. Mr. Doney's comments allege that the Commission's Order No. 5091b violates PURPA by not recognizing <u>each utility's</u> long-term avoided costs. The Commission finds that the resulting prices follow the FERC's intent. It is interesting to note that Mitex has criticized the Commission for not using <u>regional</u> data in setting avoided costs.

F. Other Comments

130. In addition to the above comments, the Commission received written comments from: (1) five irrigation districts[14]; (2) E.F. Hutton; (3) City of Livingston; and (4) Montana Small Hydro Association.

131. The irrigation districts requested the Commission to give the same considerations to alternative power producers as it does to coal-fired generation and to account for the environmental externalities of alternative energy sources in avoided cost prices.

132. For clarification purposes, the Commission would note that its charge is to set avoided cost prices to reflect the costs that utilities avoid. The request to account for externalities goes beyond the Commission's regulatory role. For example, the Montana Department of Health and Environmental Sciences may issue water and air permits to QFs such as the 30 MW coal-fired cogeneration plant at Colstrip. The Montana Department of Natural Resources and Conservation may issue certificates of public convenience and necessity to some relatively large QF projects.

133. Aside from the specific roles of these state agencies, there is no certainty that externalities are always positive. For example, plans for a 10 MW wood-fired cogeneration plant in Bozeman were dropped because of negative public input: Air and water pollution was the basis for the public opposition to the project (see for example Exh. No. 25, p. 35). A further example is evident from the Montana Department of Fish Wildlife and Park's testimony in the previous avoided cost docket: this department cautioned the Commission of the "unacceptable environmental costs" of small hydro projects (See June 17, 1983, testimony of the Montana Department of Fish, Wildlife and Parks, p. 4). Further, Montana Representative Mr. Bruce Simon testified that a number of legislators are concerned with the development of hydro projects that produce power at the wrong time of the year; Representative Simon also expressed concern for negative environmental impacts (TR 204-207).

134. The comments by E.F. Hutton are critical of the Commission's default tariff option: "The inherent instability of such a price basis is likely to discourage institutional lenders to the point of noninvestment." In response, the Commission would note its reconsideration of tariffed annual energy prices and would also suggest that Hutton consider the negotiated tariff option.

135. The Mayor of the City of Livingston filed comments that expressed deep concern with the Commission's proposed order. The City's comments suggest this Commission set avoided cost prices based on Colstrip 4 and Salem plant costs (focusing on MPC's avoided cost prices). The City also indicated that "...economic development and job creation is one of the stated intents of the PURPA law and, ... should be a factor in your decision making process."

136. Regarding the City's first point, the Commission would note that MPC's current and prospective resource plans exclude the Salem project. But, if MPC, or PP&L ever plan to include

coal-fired plants in future resource plans, the Commission will require the same utility to advise prospective QFs of the associated costs. In turn, QFs should give the negotiated tariff option consideration.

137. Regarding the City's request that prices be set to reflect economic development/employment concerns, the Commission would refer to an earlier finding that discusses the constraints imposed by PURPA. To the extent that development/employment takes place as a result of the prices in this docket, the development is economic.

138. Montana Small Hydro Association commented on changes that should be made to the proposed order. The key factor that appears to drive the Association's comments is "ratepayer neutrality." The Commission will attempt to respond to the concerns raised.

139. First, regarding the exclusion of the Kerr upgrade, the Commission notes MPC's testimony proposing to base capacity prices on hydro upgrade costs (TR 403).

140. Regarding the "avoided energy resource" discussion, the Commission would suggest that the Association consider the negotiated tariff option. As regards the default tariff option, the Commission does not agree with the Association's proposal to base avoided cost energy prices solely on the highest cost energy resource in any four year period. However, the Commission, will require each utility to tariff one year energy price estimates. The Commission will not require levelized energy (fuel cost) prices.

141. In regards to the on line/contract data issue (concerning discounting etc.), the Commission finds the on line data to be appropriate.

142. In response to the fuel offset concern raised by the Association, it appears to the Commission that MPC's fuel offset is in the same terms as the investment outlays (assuming no real fuel escalation). MPC's workpapers must provide a response to this concern and the corresponding assumption in its workpapers.

III. Methods to Compute Avoided Cost Prices

A. Avoided Cost Components

143. An attempt to define avoided costs is a first step in answering the question: "What costs are potentially avoidable?" In both electric retail rate cases and avoided cost dockets the range of relevant costs is set forth, followed by actual empirical estimates of the components.

144. The following table provides a functionalization and classification of potential avoided cost components. The three basic functions include: generation, transmission and distribution cost breakdowns. The three basic classifications include: energy (Kwh), demand (Kw) and customer cost breakdowns. It should be emphasized that the fact a cost is marginal or incremental does not mean it is avoidable. This point is discussed later in this order.

Table 2
Potential Avoided Cost Components

	Function		
Classification	Generation (1)	Transmission (2)	Distribution (3)
(1) Energy (/kwh)	E_1	E 2	E_3
(2) Demand (/kw)	D_1	D_2	D_3
(3) Customer (/customer)	C_1	C_2	C_3

145. The Procedural Order in this docket requested comments on each of these potential cost components. However, in previous avoided cost dockets, prices have been based only upon values for variables "E1" and "D1", with the exception of a line loss adjustment.

146. Following an initial discussion on short-run and long-run costs, each of the approaches will be reviewed.

B. Short-Run Versus Long-Run Costs

147. The economic distinction between the short-run and the long-run suggests underlying cost differences. Further, businesses are described as operating in the short-run and planning for the long-run. This description suggests a utility may have a different recipe (production function) for

producing power in the short-run than in the long-run. This is very likely the case given sunk fixed costs, changing technology, expectations of changing relative capital and fuel prices, and opportunities to purchase and sell power.

148. In the short-run, a utility cannot change the stock of fixed capital resources used to generate power. In other words, a utility takes its existing generating resources as a given, and attempts to minimize the total variable costs (e.g., fuel expense and O&M) of meeting any and all loads by economically dispatching existing generation resources.

149. In the long-run, existing generation resources may be replaced or augmented. That is, the long-run is sufficiently long that all factors of production (e.g., fuel, capital investment labor/management) are variable: in the long-run, a utility attempts to minimize its total costs (fixed and variable) of power production.

150. These considerations form the basis for short-run marginal costs (SRMC) and long-run marginal costs (LRMC). There is a common belief that LRMCs always exceed SRMCs. This belief, however, is incorrect. There are many different short-run marginal cost curves (e.g., daily and yearly). SRMCs oscillate above and below LRMCs. In addition, one can speak of long-run projections of SRMCs. One economic justification for building baseload plants is when SRMCs are consistently higher than LRMCs.

C. Avoided Cost Pricing Approaches

151. Potential avoided cost components include those variables in Table 2 above. Of these cost components, only generation-related energy and demand (variables "E1" and "D1") will be discussed in this section. The other cost components are discussed in a later section. The cost approaches on which the Commission requested comments included:

1. Base-Peak
2. Peaker
3. Fuel Offset
4. Revenue Requirements (the slippage/perturbation or deferral approach)
5. Opportunity purchases

6. Opportunity sales
7. Federal power prices [e.g., BPA's 7(f)]
8. Electric retail rates
9. Competitive bidding process

152. In its testimony, the Montana Consumer Counsel's witness Dr. Wilson (Exh. No. 14) discussed three long-run marginal cost approaches. Table 3 shows how these three approaches derive from the following formula:

"$LRMC = FC_B + VC_B = FC_P + VC_P$" where,

LRMC = Long-run marginal costs
FC = Fixed Costs ($/kw)
VC = Variable Costs (¢/kwh)
B and P Subscripts = Base and Peak

Table 3

Equations for Three LRMC Approaches

LRMC Approach	Demand	Energy
Base-peak	FC_P	$VC_B + (FC_B - FC_P)$
Peaker	FC_P	VC_P
Fuel Offset	$[FC_B - (VC_P - VC_B)]$	VC_P

Base-Peak Approach

153. The theoretic logic underlying the base-peak approach draws on the different functions of baseload and peakload resources. The base-peak approach reflects a major change from the "fixed-variable" method of cost allocation commonly used in the past. Whereas the "fixed-variable" approach allocates fixed capacity costs to demand charges ($/kw) and variable costs to energy charges (¢/kwh), the base-peak approach recognizes the economic reason for which high

capacity factor baseload generating plants are built, which is to provide energy rather than to meet the utility's peak loads. This is the so-called "fuel savings" argument.

154. In previous dockets the base-peak approach has been recommended for use in computing marginal costs by the following: (1) Montana Department of Natural Resources and Conservation; (2) Pacific Power and Light Company; and (3) District XI Human Resource Council, Inc.

155. In its orders in the first avoided cost docket, this Commission recognized that each utility's resource plans included various coal-fired generating plants. In an order in the second avoided cost docket, the Commission once again recognized a common denominator in each utility's resource plan, noting that on the horizon each included a baseload coal-fired generating plant.

156. Since the time of these two avoided cost dockets, however, resource additions planned by MPC and PP&L have significantly changed. While MDU's most recent resource plan includes coal-fired resources, PP&L's and MPC's recent resource plans exclude coal-fired resources. On the supply side, and for PP&L and MPC, this change in resource plans calls into question whether the Commission should continue to use coal plant costs to determine these utilities avoided costs. However, one is not restricted to using just baseload coal-fired resource costs in the basepeak approach. The separate issue of how costs should be adjusted is considered later in the discussion concerning discounting.

Peaker Approach

157. The peaker approach features prices based on the fixed and variable costs of a marginal peaking unit such as a combustion turbine. In practice, however, this approach relies upon marginal running costs (system lambda) for energy prices, and the marginal cost of additional peaking capacity for demand prices.

158. In the past, this Commission has adopted the peaker approach in developing marginal cost-based retail electric prices for both MDU (Docket No. 83.9.68) and MPC (Docket No. 80.4.2), based on both the Montana Consumer Counsel's and utility's recommendations. In the Commission's

first avoided cost docket, Dr. Power, testifying on behalf of the Commission staff, also acknowledged the economic merit of the peaker approach.

159. It is also worth noting that the FERC suggested two ways by which electric avoided cost prices could be computed, one of which appears to be the peaker approach:

> The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.
>
> If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12214, 12216 (1980).
>
> * * *
>
> The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the Principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used. Id.

Fuel-Offset Approach

160. The fuel-offset approach is the third LRMC method that may be derived from the formula discussed previously. Energy avoided costs are computed as they are in the peaker approach.

The demand component, on the other hand, is based upon the capital cost of a baseload plant, less the fuel savings it enjoys when compared to a peaking unit.

161. The fuel offset was one method proposed by MPC in a recent docket as a means to compute marginal capacity costs. MDU proposed a method, similar to the fuel offset, for computing generation-related capacity costs in Docket No. 83.9.68. And, as discussed later (technical issue on capacity prices), the fuel offset will be used to compute capacity prices out of this docket.

Revenue Requirements Approach

162. The revenue requirements approach is another method for computing avoided cost prices. The FERC discussed this method in its rules and regulations:

> One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided costs. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12214, 12216 (1980). (footnotes omitted)

163. The FERC's description, however, does not make clear how energy and capacity components would be derived from the utility's "net avoided cost" calculation. Avoided energy costs could be computed based on two production cost model runs. For example, one run would reflect the utility's optimal expansion plan (as FERC suggests); the second run could reflect 10 MWs of free QF power or 10 MWs in load reduction. Avoided capacity costs could be computed by looking at the revenue savings that result from delaying construction of new resources due to the availability of 10 MWs of QF power.

164. This approach requires computer modeling capability. MPC has such capability, given its proposal in Docket No. 83.1.2 to compute avoided capacity costs based on the reduction in MPC's revenue requirements resulting from the acquisition of QF capacity. MDU, however, does not have such computing capability (See MDU response to PSC staff Data Request No. MDU-10i). PP&L, apparently has computer capability and supports the use of the revenue requirement approach (See PP&L response to PSC staff Data Request No. PP&L-l0i).

Opportunity Purchases

165. The opportunity purchases concept is one that could be used in any of the approaches previously discussed. For example, either historic or forecasted opportunity purchases of energy could be in the utility's short-run economic dispatch analysis. If a short-run opportunity purchase of energy is cheaper than the utility's generation alternative, energy should be purchased. That is, opportunity purchases of energy should simply be reflected in calculations of variable running costs.

166. It should be noted that opportunity purchase prices affect avoided cost prices only if a utility plans to acquire such power. In other words, avoided cost prices derive from two factors. These two factors are supply and demand (this point is critical to the adoption of an avoided cost pricing approach).

Opportunity Sales

167. While the title suggests reference to nonfirm opportunities, a digression on the issue of long-term firm sales (e.g., the Black Hills Power and Light/PP&L Sale) is relevant. The Black Hills Power and Light/PP&L sale of Colstrip 3 is economically irrelevant in an avoided cost price determination. Similarly, with MPC's sale of Colstrip 4, the sales price is economically irrelevant to the determination of avoided cost prices.

168. Neither the FERC's, nor this Commission's rules make any specific reference to opportunity sales in developing avoided cost prices. In addition, one must ask: what would BHP&L or the purchaser of MPC's share of Colstrip 4 be willing to pay for one more KW or KWH? The demand side of the equation must be taken into account.

169. In a short-run context, opportunity sales are a relevant avoided cost price consideration. In terms of economic dispatch, off-system sales affect variable running costs.

170. In addition to the effect on running costs, if a utility is willing and able to sell QF power off-system, then such an opportunity sale should be factored into the avoided cost price. This is an example of an exchange where all parties are made better off. The exchange is relevant in both the short-and long-run. The Commission recognized the economic validity of opportunity costs in its 1984 Colstrip 3 cost of service order (Order No. 5051d).

Federal Power Prices

171. The Procedural Order requested comments on the economic merit of using BPA's 7(f) rate to determine avoided costs. The issues that arise around the use of this price include: (1) the FERC/PSC legal/administrative acceptance and (2) the economic rational of such a cost-based price. Each is discussed in turn.

172. First, the FERC/PSC avoided cost rules permit avoided cost prices to reflect purchased power prices. Some parties criticized this approach as being economically irrational, although that claim was challenged by the utilities.

Electric Retail Prices

173. The Procedural Order requested comments on equating avoided cost prices with electric retail rates. The benefits of such an idea appear to be the administrative ease of setting avoided cost prices. However, the costs may overwhelm the benefits, since retail prices may (or may not) reflect costs that are not avoidable (but see the below section on information barriers and the net billing option).

Competitive Bid

174. By including the concept of a competitive bid (CB) in the Procedural Order, the Commission had in mind a method by which the costs to both the economy and ratepayers would be minimized. This ground is not well trod and the Commission was exploring the economic merits of such an option, The competitive bid approach will be discussed in greater detail later in this order.

IV. The Parties' Recommended Avoided Cost Pricing Approaches

Montana-Dakota Utilities

175. Mr. Gary Paulsen testified for MDU, submitting direct (Exh No. 17) and rebuttal testimony (Exh. No. 18). In terms of policy, Mr. Paulsen claimed that the present avoided cost prices do not reflect MDU's avoided costs. As a result, the "ratepayer neutrality" objective is not achieved.

176. MDU proposed separate avoided cost prices for energy and capacity, and a metering charge. Energy-related avoided cost prices would reflect MDU's average running costs, based on a 1 MW decrement production cost modeling run (TR 327). The related avoided cost prices would reflect the Mid-Continent Area Power Pool's (MAPP) prices. These prices would vary based on contract length (less than/greater than 48 months); these prices would also only be available six (6) months per year (but, cf. TR 336). Mr. Paulsen proposed that metering-related charges be assessed QFs based on the phase of service. MDU also proposed that QFs larger than 100 KW in size negotiate prices with MDU.

177. In addition to the two contract-length based tariffs, Mr. Paulsen also proposed an "occasional power purchase" tariff. This tariff features a flat (no time differentiation) energy price, no capacity payments, and a metering charge. Under this proposal, MDU would limit to 600 kwh/month the purchases it would make from any QF (regardless of the QF's kw size).

178. In contrast to these proposals, Mr. Paulsen claimed that it is incorrect to use the MAPP Schedule "B" and "H" capacity prices in the base-peak approach (TR 213).

179. MDU's resource plan features a series of coal-plant additions, a possible combustion turbine, and MAPP purchases. Table 4 summarizes MDU's resource plan:

Table 4

MDU's Resource Additions

	Coal-Plants	Combustion-Turbine	MAPP
1985	Big Stone/Coyote[1]		Various Scheduled Purchases[2]
1986	AVS II		
1990		Generic CT[3]	
1996	AVS III[4]		

Montana Power Company

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1 MDU indicated it was pursuing a 21 MW share of Minnesota Power's Coyote Plant (TR 302).

2 MDU has proposed basing avoided cost capacity prices on certain MAPP schedule rates; assumedly, MDU plans to purchase power from these MAPP schedules (TR 325).

3 The development of a CT hinges on a Fuel Use Act exemption (TR 324).

4 MDU has no negotiated contract for AVS No. 3. other than the original letter of intent (TR 324).

180. Three witnesses presented MPC's avoided cost case including Mr. Tom Lovas (Direct--Exh. No. 19 and Rebuttal--Exh. No. 20), Mr. Richard Cromer (Direct--Exh. No. 21 and Rubuttal--Exh. No. 22) and Mr. Jack Haffey (Direct--Exh. No. 23).

181. Mr. Lovas supplied MPC's proposed method for computing avoided cost prices. The proposal reflects the importance of resource need (timing) and "ratepayer neutrality." Mr. Lovas noted that a proper avoided cost price would reflect the present value of revenue requirement savings based on the current resource plan. Mr. Lovas testified that the Company's hydro upgrades must be included in a calculation of capacity prices (TR 403). In contrast to this ideal, Lovas noted that the current levelized nominal avoided cost prices ignore resource timing and the dynamics of system load levels. The current method also overstates Colstrip 3 and 4 capital costs due to escalating historic costs.

182. In achieving the ideal basis for avoided cost prices, that being the present value of revenue requirement savings, Mr. Lovas proposed the same method tendered in the two previous avoided cost dockets (see Data Response MPSC No. 2-6 to the Commission Staff). As a result, the energy portion of the avoided cost price would reflect system running costs. The capacity portion of the avoided cost price would reflect the deferral value of capacity additions.

183. In Docket No. 83.1.2, MPC computed avoided energy costs based on two production cost modeling runs, a base run and a decrement run that assumed 10 MWs of zero-cost QF production. The capacity portion, in Docket No. 83.1.2, was computed based on the deferral value of MPC's resource plan.

184. In addition to this approach, Mr. Lovas agreed that the base-peak method could be used if certain hydro upgrades were substituted for baseload and peakload plants (TR 411).

185. MPC's "tentative" resource plan is set forth in the following table:

Table 5

MPC's Resource Additions[1]

	Hydro Upgrades	QFS	Purchases
1985		Various QF Resources Come online from year 1985 to year 2008[2]	
1987	Milltown		
1989	See purchases		Purchased power may derive from numerous sources[3]

1 This is for "Base Case" generation additions only and derives from Table 9 of MPC's Projection Of Electric Loads and Resources (see MCC Data Request of March 11, 1985 to MCP No. 1-1 in Docket No. 84.10.64).

2 QF resources in the amount of 3 average Mws are assumed on-line in 1985; by year 2008, 149 average MWS are assumed on line (ibid).

3 Purchased power includes resources from: BPA (peak purchases), other utilities and seasonal exchanges (TR 400, 401). If purchases are not available, certain hydro upgrades will be pursued (Kerr, Thompson Falls, Ryan and development at Hebgen).

186. Finally, MPC proposed a cost tracking mechanism. This mechanism, a Power Cost and Credit Clause, would feature semiannual filings to recover avoided cost and other expenses.

Pacific Power and Light

187. Four witnesses presented PP&L's avoided cost case including Mr. Dennis Steinberg (Direct--Exh. Nos. 1 and 2, and Rebuttal--Exh. Nos. 8 and 9), Mr. William Wordley (Direct--Exh Nos. 3 and 4, and Rebuttal--Exh. No. 10), Mr. Jerry Rust (Direct-Exh. Nos. 6 and 7, and Rebuttal--Exh. No. 11) and Mr. Tim Watson (Rebuttal--Exh. No. 12).

188. PP&L has split its future load/resource balance into two time periods. The first period runs from 1985 to 1993 and is one of resource sufficiency. The second period begins in 1993, and is one of resource deficiency. In either time period, PP&L's policy objective is to achieve ratepayer neutrality.

189. Mr. Steinberg supplied PP&L's proposed avoided cost price basis for the short-term (resource sufficiency) period. Short-term energy-related avoided cost prices reflect the benefit of QF power production and are comprised of three parts: (1) system fuel costs (assuming a 10 MW decrement production cost modeling run); (2) purchase power costs; and (3) nonfirm wholesale power revenues. This latter part is referred to as the "opportunity cost" portion of the proposal.

190. PP&L proposed to pay a capacity-related avoided cost price in the short term if a QF's power is reliable, dispatchable and flexible (TR 82, 83). PP&L would propose to levelize capacity payments but not earlier than seven years prior to a BPA power purchase.

191. In the long-term, after 1993, PP&L proposed to base avoided cost prices on BPA's 7(f) rate. The energy and capacity portions would be split out 77 percent and 23 percent respectively (TR 41, 42). PP&L's Long-term -- beyond 1993 -- resource plans include cost-effective conservation measures and purchases from BPA's 7(f) rate.

Montana Consumer Counsel

192. Dr. Wilson testified for the MCC, submitting direct (Exh. No. 14) and rebuttal testimony (Exh. No. 15). The MCC set forth general policy concerns and surveyed the various analytical and conceptual bases of avoided cost prices. These concerns will be reviewed in turn, followed by the MCC's comments on other parties' avoided cost price proposals.

193. MCC's policy concerns include: (1) ratepayer neutrality: a policy should not be imposed that increased costs to ratepayers. At worst ratepayers should be no worse off than without QF power (TR 140, 169-170); (2) a need for consistent standards for the treatment of: (i) alternative energy suppliers including utilities, QFs, and conservation, (ii) utility revenue requirement purposes, and (iii) rate design (retail); (3) accurate avoided costs to encourage optimal QF development and minimize the misallocation of resources, and (4) dynamic efficiency: the flexibility requirements of balancing supply and demand (TR 161).

194. The MCC set forth the following avoided cost price options:

1. Regional avoided cost;
2. Comparative regional and inter-regional sales and purchases;
3. Long run marginal cost;
4. Total revenue requirement;
5. Competitive bid.

195. Regional avoided cost data sources include BPA's 7(f) rate, and avoided costs that the Northwest Power Planning Council might develop. Long-run marginal cost approaches include the previously discussed base peak, peaker and fuel offset methods.

196. Of these various approaches for computing avoided cost prices, Dr. Wilson preferred the peaker approach and the competitive bid concept (Exh. No. 14, pp. 33, 34 and 45-57, and TR 176, 177). Dr. Wilson characterized the base-peak approach as an inferior approach on which to base avoided cost prices. This criticism is due to the absence of a resource ceiling or limit on QF resource acquisitions (Exh. No. 14, p. 56, TR 176, 177, and 191 and Data Response JW-20-ii to the Commission Staff). In contrast to the peaker approach, Dr. Wilson stated that the revenue requirements approach is not readily verifiable (TR 109).

197. Dr. Wilson found the competitive bid concept as a means to reconcile policy concerns, noting no apparent bar to its use (Exh. No. 14, pp. 45-57). The party with the lowest bid would, in effect, establish a price signal that could, in turn, be the basis of avoided cost prices (Exh. No. 14, App. A., P. 4).

198. Dr. Wilson testified that the competitive bid approach achieves the following: (1) it insures that avoided cost prices satisfy the PURPA guidelines previously discussed; (2) it precludes wasteful resource development (TR 178), and (3) in the case of MDU and PP&L, may provide cost-effective resource development on a multi-state basis.

199. In terms of whose perspective is relevant in developing avoided cost prices, Dr. Wilson was sympathetic to Dr. Power's position. In sharp contrast to Dr. Power, however, Dr. Wilson stated that costs to consumers should not be raised for purposes of developing a QF industry (TR 158). Dr. Wilson agreed with Dr. Power in that, if this Commission fails to disallow future excess costs, then injecting competition in the short run (assumedly at greater than opportunity costs) is worthwhile (TR 160).

200. The bottom line to Dr. Wilson's proposal appears to be consistent treatment of QF and utility resource additions (See MCC Data Response JW-9-i to the Commission Staff). If a utility is both surplus and attempting to rate base a resource, cost disallowances down to market value are in order (TR 173). The resulting market value would also be the avoided cost price. However, Dr. Wilson noted that if a utility resource is rate based at greater than market value, he believes that consistent treatment of QF resources should not follow: QFs should receive avoided cost payments less than that received by the utility for its rate based resources (See MCC Data Response No. JW-21-i to the Commission Staff).

MCC on MDU

201. For MDU, Dr. Wilson testified that the utility's AVS III resource is an avoidable resource on which avoided cost prices could be based (TR 130, 131). While Dr. Wilson conceded that MDU's AVS II and Big Stone resources are not avoidable, he stated that AVS II costs may serve as a proxy for system avoided costs (TR 134), or as a reasonable basis via the existing basepeak approach (Exh. No. 15, p.20). But, on the other hand, Dr. Wilson did not recommend retention of the base-peak approach (MCC Data response No. 20-ii to the PSC staff.)

202. Like MDU (TR 331), Dr. Wilson stated that it would not be correct to use the MAPP Schedule "B" and "H" capacity costs together in a base-peak calculation (TR 213, but see Exh. No.

15, p. 23). Unlike MDU, however, Dr. Wilson claimed that the MAPP power pool rates are an economically inappropriate bases for avoided cost prices (Exh. No. 15, pp. 21, 22).

MCC on MPC

203. For MPC, Dr. Wilson did not suggest a specific resource on which to base avoided cost prices (but see Exh. No. 15, p. 7). On the contrary, Dr. Wilson made explicit which resources avoided cost prices should not be based: Given the regional power surplus, the Commission's exclusion of Colstrip 3 from MPC's rate base, and the Commission's suggestion that Colstrip 3 may not be a cost effective resource, Dr. Wilson suggested that a reexamination of avoided cost methods is necessary (Exh. No. 14, pp. 12, 21, 31).

204. Perhaps most importantly, Dr. Wilson stated that if any part of Colstrip 3 is excess plant, the excess plant should have economic precedence over new alternative capacity commitments. He stated that it is obviously wasteful to commit society's scarce resources to more plant if Colstrip 3 is excess: Colstrip 3 is a sunk cost from a "resource allocation efficiency" standpoint. The only exception is if the total costs of new generation are cheaper than Colstrip's variable operating cost alone (Exh. No. 14, App. A., p. 23).

MCC on PP&L

205. For PP&L, Dr. Wilson characterized BPA's 7(f) rate as the least desirable basis for PP&L's avoided cost prices (TR 123, 125, 126 and 158). Dr. Wilson's concern with BPA's 7(f) rate was simply that the 7(f) rate reflects the allocated average revenue requirement of the 7(f) pool and, as a result, is only a valid "second best" avoided cost proxy. For the short term, Dr. Wilson, unlike PP&L, argued for a capacity credit, even though additional QF power does not reduce the utility's construction program (Exh. No. 14, p. 42, and TR 200).

Small Hydro Power Interests

206. Dr. Thomas M. Power submitted direct (Exh No. 24) and rebuttal (Exh. No. 25) testimony on behalf of several small hydro power interests, including Montana Renewable Resources, Inc., Montana Small Hydro Association, Greenfield Irrigation District and Mitex, Inc.

207. In terms of policy objectives, Dr. Power set forth the following concerns: (1) the Commission's prices should reduce monopsony power; (2) those prices should minimize long-run

generation costs; (3) Montana should move away from reliance on, and the environmental impacts of, large thermal plants (but, see Dr. Power's rebuttal at p. 35); (4) the Commission should avoid the rate shock associated with large plants and (5) Montana should develop more reliable less costly service with small dispersed QFs.

208. Dr. Power did, with certain qualifications, concede that "ratepayer neutrality" is a relevant policy objective. Dr. Power's qualification was that ratepayer neutrality is not judged solely in a short-term sense: the ultimate (long run) intent of PURPA is that ratepayers will be better off and not just neutral (TR 524).

209. In terms of a preferred avoided cost approach, Dr. Power stated that the base-peak should be retained. Moreover, according to Dr. Power, because coal plants are the marginal plants, the cost of coal plants (Colstrip 3) should be used in the base-peak approach (TR 498, 600, 601 and Exh. No. 24, p. 18). Because short-run cost approaches do not achieve the above policy objectives, they should not be used. In this docket, Dr. Power equates short-run cost approaches with "cut-throat" competition (but, See Dr. Power's testimony at page 14 in Docket No. 81.2.15).

210. Dr. Power, in contrast to Dr. Wilson, is opposed to a competitive bid process. While Dr. Power argues that a competitive bid is the ultimate objective, it is, according to Dr. Power, premature to adopt such a concept today (TR 508, 627); Dr. Power stated that a transition plan to a competitive bid solution should be set in motion (TR 509). Dr. Power claimed that the BPA 7(f) rate should be rejected as an avoided cost price basis.

211. Dr. Power argued that in addition to an avoided cost price based on the base-peak approach (using coal plant and combustion turbine costs, and escalated to 1985 dollars), certain transmission costs must be included in the price. In the case of MPC, the amount should reflect the Commission's rate base decision in the current retail case (TR 618). In addition to including transmission costs, Dr. Power argued that (1) the coal plant's capacity factor should be lowered to 65 percent; (2) overhead and common costs should be reflected in the avoided cost price; and (3) QFs should be paid additional transmission-related costs if it can be demonstrated that the utility will avoid such costs.

212. In terms of load/resource plans, Dr. Power stated that the present surplus (for MPC and PP&L) is a short-run phenomenon. Dr. Power further characterized the surplus as no accident and possibly a monopsonistic strategy: Since 1977 utilities could have analyzed and incorporated into their resource plans prospective QF power supplies (Exh. No. 24-, pp. 7-15).

Superior Energy Inc.

213. Dr. Ed Whitelaw provided rebuttal testimony (Exh. No. 16) on behalf of Superior Energy Inc. (hereafter "Superior").

214. Dr. Whitelaw set forth a number of policy concerns underlying his proposal to base avoided cost on a utility's most recent plant additions. These concerns were: (1) to ensure of the continued development of a least-cost mix of generating capacity; (2) to encourage the move to free-market competition; (3) focus on small resources to meet future growth; (4) to encourage nonutility developers and (5) to assure meeting the objective of ratepayer neutrality (TR 253).

215. Dr. Whitelaw recommended two actions to correct for the monopsony advantages enjoyed by utilities (Exh. No. 16., pp. 12, 14, 18): (1) exclude excess utility capacity from rate base until needed and (2) set avoided cost prices equal to the marginal cost of the last facility built by a utility unless the last resource is "atypical" of the utility's current and anticipated mix of resources (Exh. No. 16, p. 21).

216. While Dr. Whitelaw argued that the Commission should look at a utility's last facility to estimate long-run incremental costs (ibid, pp. 20-22, 24, 26), he dismissed the use of a short-run incremental cost estimate because, in part, it requires the "...Commission to second-guess each utility's resource plan" (Exh. No. 16, pp. 16, 23-25).

217. Dr. Whitelaw stated no preference for any particular analytical approach for computing avoided cost prices, but noted that the base-peak approach seemed warranted. According to Dr. Whitelaw, the costs of the last facility are what is crucial in setting avoided cost prices.

218. Dr. Whitelaw did state when short-run incremental cost pricing is appropriate:

> Q: Do short-run incremental costs have any role in the determination of avoided costs?
>
> A: Yes. The Commission should base avoided cost rates on short-run incremental costs when the expected availability of

> power from QFs does not extend until the time when the utility intends to begin initiating steps to secure its own additional resources. That is, short-run costs should apply to short-run contracts between an independent producer and a utility. (Exh. No. 16, p. 25)

219. Regarding the competitive bid concept, Dr. Whitelaw, unlike Dr. Power, stated that the idea is a "nice step" toward the apparent final objective of greater reliance on competition; however, it is premature to currently get into competitive bidding (TR 264, 265). Dr. Whitelaw's arguments for not adopting the CB concept were: (1) the competitive bid relies on a "strong assumption" that "none of the participants enjoy price distorting or cost distorting or market distorting power," and (2) "competition doesn't serve the competitive solution as we like to think of it, unless the conditions of competition are met and they simply are not yet met in Montana." (TR 269, 270)

Rural Energy Development Association

220. Mr. Jeff Jordan submitted pre-filed direct testimony on behalf of REDA (Exh. No. 30). Mr. Jordan's points include: (1) a utility's resource plan, short-run operating costs and melded rates are all irrelevant in setting avoided cost prices; (2) avoided costs are best measured based on resource costs recently added to the rate base (or to be added in the near future); and (3) the base-peak approach should be used.

V. Commission Decision

A. Policy Overview

221. First, it appears clear to the Commission that in the absence or PURPA, utilities would not have voluntarily acquired any QF capacity at this time. To the Commission's knowledge, MPC is the only utility in Montana with any QF power on line. And for the recent past, it appears clear to the Commission that lesser cost resources could have been developed to the economy's and ratepayers' benefit.

222. With MPC it appears that substantial QF power could have come on line at costs to ratepayers less than the costs of Colstrip Units 3 and 4. While one can bicker over the soundness of

the avoided cost prices that resulted from the previous two avoided cost dockets, in the case of MPC the 35 year fully levelized avoided cost rate is not substantially different from what MPC estimates to be the levelized annual revenue requirement for Colstrip 3 (Compare MPC's 7 ¢/kwh levelized cost in "nominal terms" in Data Response No. 1-MPG-1 to the Commission Staff, with the current 35 year fully levelized avoided cost price of about 6.4 ¢/kwh and $98/kw.) Moreover, while the Commission has no precise knowledge of QF supply curves, it is evident that, in the case of MPC, there is a substantial potential supply of QF power at or below these costs: In 1984, MPC estimated the range of "possible exposure" to lie between 200 and 325 MWs (TR 417 and Exh. No. 25, p. 25). There is an equally impressive response to the avoided cost prices this Commission set for PP&L (TR 489).

223. However, the Commission finds inappropriate some parties' proposals to continue tariffing avoided cost price based on the escalated costs of Colstrip 3 and/or 4. MPC and PP&L presently have adequate baseload generating capacity, and have no plans to add additional baseload coal-fired generation plants in their respective long range plans. To invest the economy's scarce resources, based on the those costs, would result in unnecessary social investments and, in addition, would be burdensome to MPC's and PP&L's ratepayers. In addition, the business of optimal resource planning is complex. The existence of a marginal cost does not mean the cost will actually be avoided. There are reliability, maintenance timing, location, dispatchability, and sizing considerations that must be taken into account in designing a least cost resource expansion plan.

224. In this docket, the Commission has decided to revise the current avoided cost pricing mechanism. The Commission believes that the change will inspire the utilities to begin analyzing the economic merits of QF power.

225. The options available to the Commission for setting avoided cost prices are numerous. At one end of the spectrum is the competitive bid option. All but MDU and MPC gave this option favorable mention. One issue regarding this option is whether it would be implemented on a short-term and/or long-term basis. The short-term would feature a bidding of short-run costs. The long-term would feature a bidding of assumedly fully levelized costs. Although there are many questions to be answered, there is near agreement in this docket, including this Commission, that the

competitive bid is a possible policy solution to any existing impediments to efficient electric generation.

226. Implementation of a competitive bid may, however, involve certain institutional changes. Dr. Power has enumerated certain questions that may need to be resolved, including: (1) need for a state agency to identify utility resource needs, and (2) whether a utility's transmission system must be opened to common carriage. In addition, there is Dr. Whitelaw's concern that a competitive bid relies upon the assumption that none of the participants enjoy price, cost, or market distorting power, and that a competitive bid should not be implemented unless a competitive market is in place. In contrast to these two positions, however, Dr. Wilson argues that a competitive bid is a means by which this Commission can reconcile avoided cost pricing policy issues. Based on these and other concerns, this Commission finds it would be premature to implement a competitive bid out of this docket. A later proceeding will be needed to investigate how a bid process should be implemented.

227. The Commission's decision in this docket is to provide two avoided cost pricing options. The first is tariffed, and serves as a default option. The second option is simply to allow negotiated prices. As with the competitive bid, there are degrees to which the two options may be applied. The first, or tariffed default option, could apply to just QFs, or to QFs and utilities. Out of this docket, the tariffed default option will only apply to QFs. Clearly, Dr. Wilson for one, would argue for equal treatment of QF and utility resources.

228. The second, or the negotiated option, is essentially a relaxation of a pure competitive bid. The negotiated option may proceed by a QF initiating discussions with the utilities. In turn, the utilities will have cost estimates and operating criteria for their planned resources. A utility should acquire QF resources to the extent that such resources meet the operating criteria at equal to or a lesser cost than the same utility's own resources. The negotiated option could be initiated by the utilities putting out a request for resources.

B. Montana-Dakota Utilities Co.

Tariffed Prices

229. The Commission finds that MDU' s proposals should be adopted, as modified below. First, with regard to energy prices, marginal running costs must be computed and adjusted according to the technical issue discussion on running costs that follows with refinements to accommodate MDU's time differentiated energy price proposal. In contrast to MDU's proposal in this docket, which is to not include any tariffed recognition of line losses, O&M, fuel inventory and working capital, MPC proposed such adjustments in Docket No. 83.1.2. It is unclear to the Commission why such costs are avoidable on one utility's system and not on another's.

230. The Commission finds no reason to limit any tariffed option to QFs less than 100 kw in size. Until such time that MDU's (or any other utility's) tariffed prices attract an uneconomic quantity of QF power, they shall remain tariffed with annual updates. The current mechanism of annually changing prices should suffice. If and when this mechanism appears too sluggish to respond to QF power supplies, the utility should contact the Commission and request a recalculation of prices.

231. With regard to capacity prices, MDU must compute and tariff the prices discussed in the technical issue section on levelized prices. In computing the prices required for the matrix, MDU must include an analysis of all prospective resource costs. At present, and based on MDU's testimony, the analysis must include: (1) AVS III, (2) Coyote, (3) a combustion turbine, and (4) relevant MAPP prices. Then, because MDU is "chronically capacity deficient" (TR 324), MDU must compute the highest cost capacity the Company plans to acquire; in turn, such costs must be factored into the capacity price calculations for corresponding QF contract lengths (also see the technical issue discussion on capacity prices). For example, in year 1986 if the MAPP Schedule B capacity price is the highest cost capacity purchase, the capacity price will be $12.50/kw/month (for the six months MDU is capacity deficient). With, for example, a ten year QF contract, if the highest cost resource in each year is the Coyote annual cost per kw, then Coyote's costs shall serve in the calculation of real and nominally levelized capacity prices. If a QF contract overlaps time periods when MDU is capacity deficient year round, MDU must make capacity payments 12 months per year. (In a data response to the Montana Consumer Counsel (No. 6), MDU has no surplus capacity in any season after 1992.)

Occasional Power Tariff

232. For the following reasons, the Commission rejects MDU's proposed Occasional Power Tariff: (1) the 600 kwh/month limit of energy purchases is an arbitrary ceiling; (2) there already exists a "net billing option for QFs; (3) MDU's proposal could double collect customer charges. This last response merits an explanation. Since under rate 92, MDU is not proposing time-of-day metering, an existing customer could opt for "net billing" using an existing meter. However, the same existing customer pays a basic charge to MDU each month (if an additional meter is required for net billing there is merit in a separate metering charge); and (4) although a QF may only produce power occasionally, the power production may be at the time of MDU's peak; yet, MDU proposes no capacity payment as it does with the other tariffs.

Other Issues

233. The metering charges on Rates 93 and 94 are approved. However, QFs must be informed of the option for outright purchase of a meter, or purchase with amortization.

Negotiated Prices

234. The tariffed prices should be in lieu of negotiated prices. For MDU, the negotiated option, should allow QFs the option of receiving avoided cost payment streams that are tied to specific MDU resources. For example, one or more QFs may be able to provide the combustion turbine MDU requires toward the end of this decade. Other QFs may be able to provide power similar to what MDU would otherwise obtain from the Coyote or AVS III resource. Further, with the negotiated option, and assuming a QFs resource comes on line when needed, there would not necessarily be any reason to discount costs before, for example, computing a levelized stream.

235. Finally, the Commission has a comment on MDU's position (TR 129, 132, 323 and 564-566) that AVS III is not avoidable until an apparent 113 MW deficit, at the time of the AVS III on line date, is first satisfied. This idea is perplexing.

236. Regardless of MDU's ordering of the 113 MW deficit vis-a-vis the AVS III unit, one can still assume that the cost to MDU of acquiring an additional 113 MW of resources must be at least as costly as AVS III. Otherwise, MDU should abandon its AVS III plans and vigorously pursue additional power from whatever source MDU plans to fill the additional 113 MW deficit. Also, the

113 MW deficit did not emerge in one lump sum in year 1996, but rather grew from a 1 MW deficit in year 1986 to finally equal this forecast deficit of 113 MWs in 1997.

C. Montana Power Company

237. The range of avoided cost pricing proposals for MPC covers nearly every possible approach. The Commission, however, adopts MPC's avoided cost pricing proposal submitted in both Docket No. 83.1.2 and this docket, but with certain changes. It is appropriate to first review reasons for rejecting the basepeak approach.

The Base-Peak Approach

238. At present, MPC's long-term avoided cost prices reflect, in part, the escalated costs of Colstrip 3 and 4. In Docket No. 83.1.2, this proxying idea had some relevance, but was imprecise, given the failure to discount the costs.

239. MPC's current resource plan does not include coal-fired resources. Accordingly, the use of Colstrip plant costs, as used in the base-peak approach, should be abandoned. To use historic escalated Colstrip 3 and 4 plant costs is a fabrication that totally ignores MPC's current resource plan, as well as resource need.

240. Clearly, some parties in this docket do not concur with the proposal to abandon the base-peak approach. Those that oppose changing the status quo for MPC are principally Dr. Power, Mr. Jordan and Dr. Whitelaw. However, some of these parties qualify their positions. In the case of Dr. Whitelaw, the recommendation is to base avoided cost prices on the costs of utilities' most recent plant addition, unless "...the last plant is atypical of the utility's current and anticipated mix of resources..." (Exh. No. 16, p. 21, and TR 281, 282). Colstrip 3 and 4 are clearly atypical of resources in MPC's current resource plan (as well as PP&L's). But, even if MPC had a coal resource in the plan, the associated costs should still be discounted.

241. Dr. Power also appears to relax his proposal to base avoided cost prices on the last resource's plant costs (TR 498, 524, 531, 538, 595, 602 and 608). But, there is no apparent analytical basis to this proposal: If the supply of QF power satisfies resource need, "... that rate would cease

to apply, and a lower rate would apply...". But the question is, how much lower, and based on what costs?

242. This last point indicates that the base-peak approach, as Dr. Power proposes it to be used, lacks the flexibility to respond to various load/resource conditions. Dr. Power's proposal to simply set "lower rates" is arbitrary. The missing element appears to be cost discounting, an idea accepted by all parties filing direct testimony, and opposed by all but one of the QFs Dr. Power testified on behalf of.

Tariffed Prices

243. In this order, the Commission is faced with setting forth a methodology for computing avoided energy and capacity prices for MPC that will stand the test of changing resource plans over time. Unlike PP&L, MPC has not identified a single source of incremental power supply; that is, the potential resource choices for MPC are many. For example, in this docket MPC has proposed that an avoided-cost capacity price should be, in part, based on certain hydro upgrades, as proposed in Docket No. 83.1.2 (TR 403). MPC also suggests that BPA rates be included in the same capacity price calculation. Finally, there is the prospect that MPC may at times buy Colstrip 4 power.

244. In regards to capacity prices, MPC must provide the price data discussed in the technical issue section on levelized prices. At issue then, is the appropriate resource costs that should be the basis for a capacity-price. The Commission's earlier analogy (Finding Nos. 45 through 48) provides a theoretical, if not practical, answer. MPC is currently capacity deficient; in turn, the highest cost capacity MPC plans to purchase must be factored into capacity price calculations for corresponding QF contract lengths. All options must be exhausted (e.g., Colstrip 4, Ryan, BPA 7(f) etc.).

245. The Commission finds that for the varying QF contract lengths (e.g., 5, 10 years, etc.), MPC must base capacity prices on the highest cost capacity purchases in the same time period. MPC must set forth the costs per kw for resources it plans to acquire for a 35 year period. In each year, cost estimates for each resource must be computed with the highest cost resource serving as the basis of capacity prices (also see the technical issue discussion on capacity prices). Until MPC can show cause for increasing (or decreasing) a current capacity price based on BPA's current 7(f)

capacity rates, the current capacity prices shall equal BPA's 7(f) rates. The Commission finds that until better cost evidence surfaces, the 7(f) rate is a practical estimate of the value of capacity on its entire system. In addition, it is the Commission's understanding that given current BPA load/resource conditions, seven (7) years notice is not required to take 7(f) power if an investor owned utility has a power sales contract with BPA.

246. MPC must also compute the energy price options discussed in the technical issues section on system lambda, and provide an illustrative 35 year forecast of annual energy prices.

Negotiated Prices

247. QFs must have an opportunity to negotiate avoided cost prices. The Commission finds, as noted above for MDU, that QFs which contract to time the on-line date of their resources to match that of a resource MPC would otherwise bring on line (e.g., Ryan etc.), should receive the associated incremental costs of the Company's resource; no cost discounting would be required in this case. Of course, the QF resources would also need to be qualitatively similar to those MPC would otherwise develop.

248. The Commission does not propose tariffing transmission related avoided costs (aside from line losses). However, if any of MPC's transmission investments are avoided, the responsible QFs should be so remunerated.

The Cost Tracking Mechanism

249. The Commission approves of MPC's proposed cost tracking mechanism, but only for avoided cost-related expenses. Such costs may be recovered once per year. MPC should attempt to coordinate cost recovery with ongoing and expected dockets so as to minimize the number of annual price changes to customers.

D. Pacific Power and Light

250. The Commission accepts PP&L's proposed short-term and long-term avoided cost prices, but with certain changes. The Commission notes that the base-peak approach, using Colstrip 3 and 4 cost data, is currently an inappropriate avoided cost price basis for PP&L (as it is for MPC).

Tariffed Prices

251. For the default tariffed option, the Commission finds that QFs must have the following price options: (1) PP&L's short-term proposal (as adjusted by the Commission) and (2) an option similar to PP&L's proposal but differing in the energy payment. Both are discussed in the technical issues section on system lambda. (PP&L's proposal to offer fixed energy prices is approved but must be offered in the negotiated option.) PP&L must include language in its tariff indicating the availability of the energy price option that varies monthly.

252. There should be no difficulty for PP&L in computing the value for opportunity sales. Because the Oregon Commission disallows this value, PP&L must already make an annual estimate of the avoided energy cost without the adder. In fact, PP&L has indicated that the annual average value is 2.5 mills/kwh prior to making an adjustment for BPA transmission costs. The Commission finds that PP&L must show these calculations and net from this 2.5 mill value an annual average estimate of BPA transmission costs (which range up to 3 mills/kwh) (TR 72 and 76). This net opportunity sales value must be included with the annual and monthly energy price estimates.

253. The Commission finds necessary certain changes to PP&L's proposed capacity prices. First, the Company must recompute its levelized capacity prices to be consistent with the recent marginal cost study assumptions in Docket No. 85.10.41 (particularly columns (8) and (9) of the exhibit on generation marginal costs). As necessary, capacity price calculations must be made pursuant to the technical issue discussion on capacity prices.

254. Second, the Commission finds that QFs must have an option of fixed real-levelized capacity prices. With this option, the assumptions that PP&L included in the corresponding nominally levelized capacity prices should be fixed. (PP&L's tariff must reflect this option.)

<u>Negotiated Prices</u>

255. Given that PP&L's long-term resource plan only features BPA's 7(f) rate as the avoidable resource, and PP&L proposes that the same costs be the avoided cost price basis, the issue of price negotiation, at this time, is limited. The only candidate for price negotiation would appear to be any avoidable transmission investments.

VI. Technical Issues

A. Running Costs (System Lambda)

256. Each utility must compute system lambda in the following manner and make the following adjustments.

257. Three tariffed energy price options shall be available to QFs. The first shall reflect each utility's best estimate of a forecast annual average system lambda based on a 10 MW decrement. The second option shall reflect each utility's system lambda in the prior month assuming a 1 MW decrement calculation. The third shall reflect a real levelization, based on a 10 MW decrement, of forecast system lambdas for up to 35 year contract lengths. The reason for the second option stems from a concern for possible forecasting errors. Two examples demonstrate this concern.

258. First, the use of actual data as opposed to forecast data will allow for the reflection of all loads, both native and off-system, in the calculation (TR 193). While one utility indicated that estimated off-system sales should be included with marginal running costs (see PP&L Data Response A11-1-D to the PSC Commission Staff), another utility's estimates sharply diverge from actual experience (TR 401). The difference, for MPC in this case, is 181 AVG MW versus 115.4 AVG MW (based on five years of actual versus five years of forecast data): nearly a 60 percent difference. The Commission finds that all loads must be reflected in the running cost calculations when computing monthly, annual average system lambdas, and the real levelized option.

259. Second, in Docket No. 83.9.68, MDU's forecasts of marginal energy costs for 1985 and for winter/summer peak and offpeak periods equals 6.3¢/3.1¢ and 4.9¢/2.2¢ respectively. (TR 340) Two years later, in the present avoided cost docket, the 1985 forecast is 2.3¢ (peak) and 1.8¢ (off-peak): given the magnitude of these forecast errors, the use of historic/actual data would appear to be a major improvement over forecast data.

260. Running costs must be adjusted upward, in all three options, to reflect the following cost refinements for the relevant marginal generation resource (e.g., C-3 or 4, Centralia, purchased power, AVS #2, 3 etc.): (1) variable O&M; (2) avoided fuel inventory and (3) avoided working capital. It should be noted that MPC proposed to include these items in its Docket No. 83.1.2 avoided cost proposal (Direct Testimony of Tom Lovas, Exhibit TA 1-2A).

261. The adjusted running costs must be further adjusted for transmission line losses. The percent adjustment should equal 8.3 percent per kwh as adopted in the Commission's two previous avoided cost dockets.

262. Finally, and again for each tariffed energy price options, each utility must compute and include an adjustment for off-system opportunity sales. PP&L has proposed such an adjustment in this docket. However, in the calculation each utility must also net out any associated costs (see TR 76, ll. 7-9). In fact, and with each option, each utility may offer QFs an energy price up to the value of off-system opportunity sales.

263. Before leaving this technical issue, the Commission is obligated to respond to a proposal by the MCC to model an efficiently planned utility. Specifically, Dr. Wilson suggests excluding Colstrip 3 from PROMOD runs used to determine running costs.

264. This suggestion by Dr. Wilson appears inconsistent on two counts. First, Colstrip 3 is a sunk resource. Dr. Wilson's own testimony recognizes this fact (Exh. No. 14, pp. 49, 50, and App. A. pp. 22-26). Yet, Dr. Wilson apparently argues in favor of raising the avoided cost price to reflect an efficiently run utility (TR 211-213 and Exh. No. 14, App. A, p. 22).

265. Secondly, there should be a consistent recommended application of the peaker approach across dockets. On one hand, surplus power and resource exclusion from a PROMOD run go hand in hand. What about MDU which admits chronic deficits? Why hasn't Dr. Wilson (or associates) proposed lowering running costs for MDU in either this docket or in Docket No 83.9.68?

B. Discounting

266. The Commission's January 17, 1985, Procedural Order requested parties to address the issue of cost discounting (issue No. II (c) in the Procedural Order). The issue of discounting arises in this docket in computing certain prices. Those parties responding to this issue, except for Dr. Power, agree that costs should be discounted to account for the "time value of money." With Dr. Power's proposal to not discount, but rather de-escalate future costs, it is immaterial whether ratepayers need a resource today, 20 years from now or 2000 years from now. (<u>See</u> for example cross-examination of Dr. Power in Docket No. 83.9.67, TR 4941.)

267. The Commission's failure to discount avoided costs in earlier avoided cost dockets was criticized by an economist for the Montana Department of Natural Resources and Conservation. In a letter to the Commission, the Northwest Power Planning Council indicated that it also applies cost discounting. The FERC also recognized the economic soundness of discounting future costs to a present value for purposes of computing avoided cost prices. The Commission finds that, as necessary, avoided costs must be discounted prior to computing prices.

268. If avoided cost payments are to begin presently for future costs, then precisely what costs are to be discounted is a concern to this Commission. This issue raises the dilemma of whose perspective is relevant in developing avoided cost prices. The issue is simply, whether the annual actual costs incurred by a utility for a future plant should be discounted to the present, or should the summation of annual accounting costs, which would be rate based, be discounted. The two discounted present values are not necessarily equal, as is evident from Table 6 below.

Table 6

Illustrative Cost Discounting Examples[1]

Year (1)	Cash Flow W/AFUDC (2)	N (3)	Discounted Value of Col. (2) (4)
1985	$ 59	0	$ 59
1986	44	1	39
1987	39	2	31
1988	41	3	29
1989	78	4	50
1990	459	5	260
1991	1,251	6	634
1992	1,798	7	813
1993	8,966	8	3,621
1994	4,718	9	1,701
Discounted Present Value	$ 6,294[2]		$ 7,237[3]

[1] Data Source: MPC's Cost of Service/Rate Design Supplemental Workpapers. Fuel Offset Tab, page 10 or 12, Docket No. 83.9.67. Partial data for the Kerr upgrade.

269. In other words, the perspective from which one thinks costs should be minimized shapes the avoided cost price. The $6,249 figure, reflects the discounted present value of the cost MPC would request to rate base. The $7,237 reflects the discounted present value of the annual costs MPC expects to incur. The former (lesser) value reflects the present value of eventual ratepayer costs--the costs to be ratebased. The latter value reflects the present value of economic costs as they are incurred by the utility, and is in the spirit of the FERC rules. The Commission finds actual annual economic costs must be discounted. With the negotiated option costs would not necessarily have to be discounted.

C. Carrying Charges

270. The Procedural Order inquired into what type of carrying charge is appropriate to annualize costs. At issue was the choice between real and nominal carrying charges. Real carrying charges are net of inflation. With the possible exception of Wilson (Exh. No. 14, App. A, p. 13 and TR 187, 188), parties responding to the procedural order issue recommended real carrying charges. The use of real carrying charges must be continued in this docket. The real carrying charge should reflect the following cost components: (1) insurance, (2) depreciation, (3) weighted cost of capital, (4) property taxes (5) state and federal taxes.

D. Levelized Prices

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[2] The Figure $6,294 was computed by 1) adding up the annual costs ($17,453), as if they would be rate based in year 1994, and 2) discounting this sum back to 1985 using a 12 percent discount rate (N=9).

[3] The $7,237 figure is the sum of the discounted values of each years cost.

271. Avoided cost prices are presently levelized in three formats: (1) fully levelized (in nominal terms) (2) partially levelized and (3) fully escalating (effectively a real levelization). The issue of levelization is an issue of risk taking.

272. Most parties responded to this issue advocating real levelization. Both Dr. Power and Mr. Jordan seem to favor real levelization (TR 285, 603). PP&L's capacity payments, however, appear levelized in nominal terms (Exh. No. 7, App. A). MPC claims that nominal levelization assumes a plant is needed each year (Exh. No. 19, p. 7) and that such an incentive is inappropriate (ibid, p. 18). Yet, in Docket No. 83.1.2, MPC proposed to offer nominally levelized capacity payments to QFs.

273. For the tariffed rate option, the Commission finds that the energy component will not be levelized in nominal terms, but as one option will be levelized in real terms. QFs must have the choice (with the tariffed option) of capacity prices levelized in real or nominal terms: If capacity is not levelized, there would be no price distinction between contracts of varying lengths. If real levelization is used, there may be a slight price distinction; nominal levelization while not economically precise, will emphasize the impact of contract length. Further, with the real levelized option QFs shall have the choice of: (1) locking in the same escalation rate(s) (and other assumptions) used in the nominally levelized option or (2) leaving the escalation rates (and other assumptions) to an annual adjustment.

274. Each utility must compute and file a matrix of nominally levelized capacity prices. In turn, the matrix must reflect variations in two parameters: (1) the QF on-line date and (2) the length of levelization. As regards the on-line date, ten years, beginning with 1986 and ending with 1995, must be included. The length of levelization must include 5 to 35 years with five year increments (e.g., 5, 10, 15). In each subsequent year the beginning year in the matrix will advance by one year.

E. Capacity Prices

275. At issue is how each utility should compute capacity prices. An earlier discussion (Finding Nos. 46 and 48 above) provided the Commission's findings on the proper basis for

determining which resources shall be included in a capacity price calculation. There remains the issue of whether all capacity costs are to be included in the capacity price. To this end, the Commission finds that if resources with baseload characteristics are the highest cost resources, then the fuel offset approach must be used to compute capacity costs. (See Dr. Wilson's LRMC theorem in Finding No. 152 above and Table 3). Such a calculation would be required, for example, with Coyote, AVS III and C-4. MPC has recognized the validity of such a calculation for its hydro upgrades.

276. If capacity costs vary by season (e.g., BPA's 7(f) rate), then prices must also vary; QFs must at least have the option of seasonally differentiated prices if there exists evidence of cost variation.

VII. Other Issues

277. Several issues remain to be discussed including: (1) information barriers; (2) an implementation phase for utility compliance (filing of workpapers etc.), and (3) a prospective rulemaking.

A. Information Barriers

278. The utilities should provide avoided cost pricing information to both consumers and producers. First, with regard to information provided to consumers, the January 17, 1985 Procedural Order [issue No. VI D. (b)], raised the issue of avoided cost prices equaling retail prices. Additionally, parties were invited to propose changes to the Commission's rules (ARM 38.5.1901-1908). Further, no party proposed revisions to ARM 38.5.1905(6) dealing with the "net billing" option.

279. The Commission finds that once per year each utility must provide to every electric customer information on the "net billing" option. Such information must be included along with the customers' bills. The first such notification should occur in 1986.

280. Each utility must provide to each prospective QF its resource plans for generation and transmission investments. In order to negotiate nontariffed avoided cost prices, prospective QFs need

information. One example underscoring the importance of such information relates to the mobility of the Bozeman wood plant -- now the Livingston wood plant -- vis-a-vis the proximity to an MPC incremental transmission investment. If requested, the utility must provide prospective QFs cost breakdowns for incremental resources. Such data must reflect estimated annual costs prior to ratebasing and not ratebase (revenue requirement) costs.

B. Implementation

281. The utilities must provide the underlying cost data and workpapers for their respective avoided cost compliance prices. Such information must be provided for the tariffed and negotiated price options. In addition, all such data must be provided to nonutility intervenors in this docket when provided to the Commission. For the tariffed option, each utility must document the development of actual running costs, and the associated working capital, fuel inventory and O&M adders. Precisely how off-system loads and off-system opportunity sales affect running costs, must also be documented.

282. Regarding historic monthly energy costs, each utility must provide resulting energy prices for the last four months of 1985 (one value per month), and for January and February, 1986. When filing the June update of avoided cost prices, each utility must, at the same time, provide the monthly energy price calculations for the previous year.

283. For illustrative purposes, each utility must compute and provide, at a minimum 35 years of forecast annual energy prices reflecting O&M, fuel inventory, working capital, off system loads, off-system opportunity sales, and line loss adjustments. It must be made clear in the tariff, however, that the price estimates are not precisely what QFs will be paid (for PP&L, however, QFs will receive these forecast fixed energy prices).

284. Regarding the negotiated price option, the Commission requests that each utility provide cost estimates for incremental resource additions. For MDU, annual cost data for the tentative combustion turbine, Coyote, and for AVS III should be filed. For MPC, annual cost data on the hydro upgrades, Colstrip 4 (if MPC plans any future purchases) and relevant BPA rate(s) must

be filed. In addition, MPC must provide unit cost estimates for any other "tentative" purchased power resources. For both utilities the annual actual cost incurrences should be provided.

285. At the time any utility decides upon a resource not in its 1985 resource plan, the same utility must submit the annual actual total expected costs associated with the resource. That is, if, for example, MPC reconsiders the Salem plant, the Commission requests notification and associated cost data. Such data must be provided prior to the utility's making a long-term contractual commitment to the resource. The purpose of such data is evident: The economy and the ratepayers deserve an opportunity for possible competitors to supplant the same resource(s) at a cost less than the utility expects to incur.

286. It is the Commission's desire that least cost resources be acquired to fill a given need, and that ultimately, similar resources be treated alike. For example, in the case of MPC, there are several resources, both potential and actual, which may be subject to reevaluation in light of the methodology contained in this order. These include Stauffer Chemical, the Bird Plant, and ECPP (or MCS, as well as any other conservation plan). As resources, it is possible that they may be subject to partial or total displacement by economical qualifying alternative sources.

287. If, for rights to purchase back power, any utility later contracts to build resources for acquisition by either a federal power market agency (PMA), or another utility, the costs at which such resources are sold to the PMA or utility must be factored into the avoided cost price signal. That is, if said costs, in the case of PP&L, for example exceed BPA's 7(f) rate, the costs would be the avoided cost price basis and not the 7(f) rate.

288. In its compliance workpapers, each utility must provide information (size, ownership percent, cost, on-line date, location) on each qualifying facility it, or one of its subsidiaries, is currently engaged in developing.

289. MPC's 1985 Projection of Electric Loads and Resources shows QF power in excess of 91 MWs in 1986, rising to 190 MWs in 2008. MPC must submit all cost and price analysis underlying this projection. In addition, MPC must provide a technology breakdown of all MWs in excess of the 91 MWs of fully negotiated power. Finally, MPC must explain the difference between these figures and the higher possible exposure of 325 Mws.

290. MPC must also provide a supply breakdown of all QF resources on line and/or fully negotiated out of Docket Nos. 81.2.15 and 83.1.2. The breakdown must be by technology (i.e., wind, hydro or cogeneration -- coal, wood, gas etc.), docket, contract length, price option (e.g., which long-term price option out of Docket No. 83.1.2), QF size in MWs and expected on-line date.

291. PP&L must provide the Company's analysis supporting the claim that this Commission's Docket No. 83.1.2 avoided cost prices would have attracted 165 MWs of QF capacity. Again, the amount must be broken down by the same parameters in the above finding.

292. Also, to better understand how PP&L's pricing proposal in this docket will operate in the future, PP&L must explain how its proposal in this docket would be implemented in, for example, years 1990 and 1995 (assuming no change from the load/resource balance provided in this docket). That is, in either of these years would PP&L's present proposal result in a distinction between the short run and the long run, whereby in the short run prices would not be fixed and in the long run they would be fixed. If the Commission's interpretation, that PP&L will only offer fixed energy prices after 1993, is wrong, then PP&L must explain why.

C. Rulemaking

293. The Commission will institute a rulemaking proceeding subsequent to the tariffing of final prices -- under the pricing methods adopted in this docket. Such a proceeding will address concerns raised by Mitex, PP&L and MDU, as well as streamline data reporting requirements to reflect decisions in this docket and to eliminate certain data filing requirements from previous dockets and rules.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Power & Light Company are public utilities within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates, terms, and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power

producers. Sections 69-3-102, 69-3-103 and 69-3-601 et seq., MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production, as set forth in PURPA, is promoted by the rates, terms and conditions established by this order.

5. The Commission's ratemaking decisions are exempt from the requirements of Montana's Environmental Policy Act, 75-1-101 et seq., MCA. The Commission interprets 75-1-201, MCA, as an exception that applies to the Commission's ratemaking activities. This proceeding is designed to establish rates, and is included in the exception.

ORDER

1. MDU, MPC and PP&L shall develop rates which are consistent with the Findings of Fact entered by the Commission in this order.

2. Proposed tariffs and requested cost data must be filed with the Commission within two weeks from the date of issue of this final order.

Done and Dated this 5th day of March, 1986 by a vote of 5-O.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

CLYDE JARVIS, Chairman

HOWARD L. ELLIS, Commissioner

TOM MONAHAN, Commissioner

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner
(Voting to Concur)

ATTEST:

Trenna Scoffield
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

CONCURRING OPINION
By John Driscoll

This order has improvements over the proposed order that make it acceptable to me. It can't erase the serious damage to efficient procurement of power that was done by both the Colstrip 3 and 4 decisions, but it does, in my mind, make some serious inroads toward opening up a competitive market for whole sale energy.

One improvement is the "pegging of energy prices" above a floor of likely system lambdas and below a ceiling of likely opportunity sales market's lambdas. The range in between is left to the utility's management in their calculation of fixed lambda based tariffs. Should some utilities be in a better position to exploit the brokering opportunities of off-system markets (California, as well as others), then the potential is here to offer fixed contract tariffs up to the ceiling.

Another improvement is that this order indirectly forces the utility to question the wisdom of fixed energy provisions in long term power contracts. While the energy portion of a fixed long term power contract from a traditional energy source (BPA, other utilities, generation subsidiaries, etc.) may still be fixed for the life of the contract under this order, it is clear that that fixed energy payment will serve as a floor for QF energy payments by its impact on the system lambda of the utility in question. One would expect less likelihood of fixed energy components in long term contracts in the future; thus another step surprisingly to at least a spot market for energy.

Finally, an important development in this order is the calculation of system lambdas based on all resources for all loads including off system sales markets. This means that we are moving headlong toward a regional avoided cost, or a regional market clearing price, or both. This strikes me as a significant improvement in the development of the wholesale electricity market.

The impact of rate basing Colstrip 3 and committing to the long term lease of Colstrip 4 will not be fully felt until we see how much energy and capacity is available at these lower prices. I believe strongly that there is already considerable negative impact. The fixed and variable costs of Colstrip 3 and 4, all of which eventually will have to be born by the Montana ratepayer, if not offset by revenues from the off-system sales market, will I think prove to be very expensive last minute purchases in the way that wholesale electricity used to be procured. The manner in which Colstrip 4, now owned by a "non utility", has been borne by the ratepayer (i.e. sale on the condition that the utility lease it back for fixed cost plus all risk), and the contract provisions that allow the facility to be spun off to a deregulated subsidiary after the market for energy clears and its a good investment, seems highly anti-competitive to power procured from Qualifying Facilities. It would be strongly advisable for all parties, including the Montana Power, to carefully watch to see how Colstrip 4 power is integrated into the utility's loads (including off-system), given the guidelines of this order. If Colstrip 4 power is not treated as the power procured from QFs in this order, the utility is just begging to be tagged with the treble damages of an anti trust action. I'm confident that this Commission would not cover the cost of those damages in utility rates.

John B. Driscoll
Montana Commissioner

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1. See National Bureau of Standards Handbook 135 on "Lifecycle Costing Manual for the Federal Energy Management Programs," by Rosalie T. Ruegg. U.S. Department of Commerce. December, 1980.

2. See Volume II 1985 Draft Technical Analysis for the Northwest Conservation and Electric Power Plan, by the Northwest Power Planning Council. (Chapter 4, p. 4-1.) August, 1985. Also see, BPA's July, 1984 report titled Generating Resources Supply Curves. Page B-1.

3. See page 17 of BPA's November, 1985 draft "1986 Resource Strategy."

4. Source: Technical Assessment Guide, p. 3-11, EPRI P-2410-SR. May, 1982.

5. See PP&L's Power Sales Agreement, Appendix C, p. 2 of 2. The 7.3 mill figure is computed as $6,371,594 minus fuel costs ($3,672,803) divided by 370,000 mwh.

6. The Commission received a 43 page document that provides the comments of: (1) Montana Small Hydro Association; (2) Greenfield Irrigation District and (3) Mitex, Inc. These parties are the same ones Dr. Thomas Power testified on behalf of. (See Finding No. 80 of Order no. 5091b). The Commission will refer to these parties as "Mitex et al.," in addressing comments.

7. The interested reader is directed to Finding Nos. 119, 120 in the Proposed Order and in turn the cited transcript pages.

8. See Public Law 95-617, Sec. 210(b). November 9, 1978.

9. RE: FERC's Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg 12216 (1980).

10. See, Volume 1, page 8-19, Figure 8-10 in the 1985 Draft Northwest Conservation and Electric Power Plan.

11. Source: Burns, Robert E., et al., June 1982. The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs. NRRI., Columbus, Ohio, p. 83.

12. Source: Nordell, Larry, 1985 Intra-agency memo. Montana Department of Natural Resources and Conservation.

13. Source: Paul A. Samuelson. Economics, 8th Edition, p. 590. McGraw Hill Book Company.

14. Including: (1) Dodson; (2) Greenfields; (3) Glasgow; (4) Malta; and (5) Milk River.